

Generating Resources Advisory Committee Meeting

October 16, 2013

Meeting Time: 9:30 A.M. to 2:45 P.M.

Meeting Location: Northwest Power and Conservation Council
851 SW 6th Ave.
5th Floor Meeting Room
Portland, OR 97204

Facilitators: Steve Simmons, Northwest Power and Conservation Council; Generating Resources Advisory Committee, Chair

Gillian Charles, Northwest Power and Conservation Council; Generating Resources Advisory Committee, Vice Chair

Note Taker: Kyle Gustafson

Attendees: *On-Site*
Gillian Charles, Northwest Power and Conservation Council
Rick Sterling, Idaho Public Utilities Commission
Keith Knitter, Grant County PUD
James Gall, Avista
Cameron Yourkowski, Renewable Northwest Project
Jimmy Lindsay, Renewable Northwest Project
Chris Johnson, Benton PUD
Greg Mendonca, PNGC Power
Kevin O'Meara, Public Power Council
Erin Erben, Eugene Water and Electric Board
Fred Heutte, Northwest Energy Coalition
Thad Roth, Energy Trust of Oregon
Jeff King, Contractor with J.C. King & Associates
Steve Simmons, Northwest Power and Conservation Council
Peter Williams, Bonneville Power Administration
Greg Nothstein, Washington State Department of Commerce
Jeff Kugel, PNGC Power
Kathleen Newman, Oregonians for Renewable Energy Progress
Michael Deen, Public Power Council
Tomás Morrissey, Pacific Northwest Utilities Conference Committee
Mike Hoffman, Pacific Northwest National Laboratory
Robert Petty, Bonneville Power Administration
Vijay Satyal, Oregon Department of Energy
Phil Obenchain, PacifiCorp
Jessica Zahnow, Argus Media
David Nightingale, Washington Utilities and Transportation Commission
Mark Pengilly, Oregonians for Renewable Energy Progress

Generating Resources Advisory Committee Meeting

October 16, 2013

Chris Robertson, CR & Associates
David Sanna, Army Corps of Engineers
Therese Hampton, Public Generating Pool
Stefan Brown, Portland General Electric

Attendees: *Via GoToMeeting*

Tom Kaiserski, Montana Department of Commerce
Howard Schwartz, Northwest Power and Conservation Council
Anna Berg, Snohomish PUD
David Clement, Seattle City Light
Robert Brown, Portland General Electric
Leann Bleakney, Northwest Power and Conservation Council
Russ Schneider, Flathead Electric Cooperative, Inc.
Galen Barbose, Lawrence Berkeley National Laboratory
Phil DeVol, Idaho Power
Elizabeth Hossner, Puget Sound Energy
Dave LeVee, PwrCast, Inc.
Travis Metcalfe, Tacoma Power
Cathy Carruthers, Tacoma Power
Lynn Marshall, California Energy Commission
Mike Murray, Benton PUD
Richard Jensen, California Energy Commission
Rick Rozanski, McMinnville Water & Light
Shirley Lindstrom, Northwest Power & Conservation Council
Zac Yanez, Snohomish PUD

Steve Simmons, Chair for the Generating Resources Advisory Committee (GRAC), called the meeting order at 9:30 A.M. He reviewed the committee meeting's agenda before the meeting participants introduced themselves.

Gillian Charles, Vice Chair of the GRAC, reminded the members what the GRAC is and its purpose. She noted that GRAC members serve a two-year charter, which began in May 2012, and act in an advisory capacity to the Council (the committee does not take votes). Charles reviewed the objectives and scope of the GRAC, which include duties such as reviewing information, vetting preliminary staff assumptions and making recommendations to the Council.

Natural Gas Combined Cycle Combustion Turbines

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

Simmons explained that the focus of today's GRAC meeting is combined cycle combustion turbines (CCCTs). He stated that CCCTs are trending toward offering more flexibility. Referring to the "Natural Gas Combined Cycle Combustion Turbines" slide, Simmons shared that CCCTs have the ability to "ramp up and down," offer "supplemental peaking capacity" and complement renewable development.

Simmons noted that CCCTs are highly efficient and have the lowest per-megawatt (MW) CO₂ production of the fossil fuel resources. He stated that there are plentiful natural gas supplies and low prices, and that recent CCCT additions include Carty in Oregon and Langley Gulch in Idaho.

Combined Cycle Dispatch Percentage of Hours on the Margin by Resource Type Winter Months

Referring to the respective slide, Simmons explained that CCCTs are important in the region because they are often on the margin and can set the electric (wholesale) price forecast.

CCCTs in the Region

Simmons noted that, in general, CCCT capacity factors are set at 85% when making levelized cost estimates. In the Northwest, actual capacity factors are lower for CCCTs. Based on the current fleet in the region, he stated that they average around 43 percent and have a range of 12 to 80 percent. Simmons said that the range varies by year and hydro conditions. The respective slide represented the years 2002 to 2011.

Development of CCCTs in PNW

Charles reviewed the history of CCCTs in the Pacific Northwest, referring to the respective slide. She noted that in 1974, the first CCCT in the region (the 600 megawatt Beaver units) began operation. Charles explained that there wasn't much development throughout the late 1970s and 1980s. In the early 1990s, the new General Electric F-class was introduced, which was more reliable than previous models and had increased efficiency. Charles stated that new technologies combined with low gas prices caused a shift from the development of coal to CCCT development.

According to Charles, in the late 1990s, there were a lot of good water years combined with utility deregulation. Utilities stopped building on their own and instead independent power producers would build in response to market need. During the 2000 energy crisis, the region experienced a very poor water year. Until then, the resource shortage that existed in the region was covered up by the good hydro years that preceded 2000. In response, she stated that what followed was a "burst" of development of CCCTs in a short period of time, primarily by independent power producers.

Natural Gas Baseload is 12% of the Region's Installed Capacity

Referring to the respective slide, Charles pointed out that as of April 2013, natural gas makes up 12 percent of the region's installed capacity. Hydro represents 55 percent, which is the majority. The slide showed that coal also represents 12 percent.

CCCT Production Dependent Upon Hydro Year

Charles explained that during any year, natural gas production depends on hydro output. She pointed out that when there is an increase in hydro production, there tends to be a relational decrease in CCCT production, as seen in 2010.

In response to Simmons' question, Charles stated that wind production started in 2006, but had an increase in production in 2009. She explained that the Council has charts—such as one for wind—that show the generation of a particular resource. This chart and others, along with the project database, are available on the Council's website under Power Supply¹.

Existing CCCT Plants in Region

Referring to the respective slide, Simmons pointed out some of the existing plants in the region. He shared that there are about 20 current CCCT projects that have an average installed capacity of 345 megawatts and an average heat rate of 7,243 British thermal units (Btu) per kilowatt hour (kWh).

The plants that Simmons highlighted include the Beaver Units and Port Westward in Clatskanie, Oregon, Langley Gulch in New Plymouth, Idaho and Coyote Springs in Boardman, Oregon. He stated that Coyote Springs uses the TransCanada GTN pipeline while the others use the Williams Northwest Gas pipeline.

Utility IRPs—Projected Future Need for Baseload Natural Gas

Charles showed the current projected need for CCCTs in the region according to the latest utility integrated resource plans (IRPs). A suggestion was made to look into any public utility or IPP acquisitions, such as the potential TransAlta purchase.

After a discussion about different plants and their forecasts, Stefan Brown with Portland General Electric shared that the Carty plant is not a substitute or replacement for the coal plant in Boardman, and that he doesn't know what the replacement for Boardman is.

State of the Art Summary, Combined Cycle Combustion Turbine

CCCT State of the Art

Simmons stated that one of the goals of the GRAC is to develop a CCCT reference plant for informational and modeling purposes. The 2012 Gas Turbine World Handbook is one source the Council used for analysis. Information that Simmons shared include:

- Generation mix restructuring to help accommodate wind and solar power generation.

¹ <http://www.nwcouncil.org/energy/powersupply/>

Generating Resources Advisory Committee Meeting

October 16, 2013

- Technological shifts will help make CCCT plants more operationally efficient at part- and minimum-load outputs.
- There is an increased focus on rapid start times and flexibility in regards to having the ability to “quickly ramp up and down.”
- There are two main factors that drive demand for CCCTs:
 1. Grid backup to support intermittent wind and solar power.
 2. Replacements for retiring coal plants and scheduled nuclear power plant shutdowns.

Simmons said that the pricing methodologies in the *Handbook* are different than those in other cost studies available. He stated that the *Handbook* authors:

- Got a consensus from project developers, owners, operators, consultants and OEM suppliers about what they considered as reasonable costs for budgeting purposes.
- Use basic engineering, procurement, and construction (EPC) contract prices, which exclude project-specific owner expenses (e.g., cost of land).
- Use “bare bones” reference plants that use an integrated gas turbine, HRSG and steam turbine that are optimized for net output and efficiency.
- Do not include costs related to add-on options like dual fuel combustion, catalytic NOx reduction, power augmentation and air inlet chilling.
- Believe that renewable integration may require additional upgrades, as well as flexible gas and steam turbine designs that will promote fast start-ups and ramping, operational flexibility and part-load efficiency.

Simmons then showed the group a chart that included information related to advanced CCCTs, manufacturers, net outputs, heat rates and prices. He noted that adjustments were made to the information in the “Heat Rate Adjusted” and “Adjusted Price \$/kW” rows to normalize the data to make the *Handbook* information more consistent with other cost and heat rate projections

James Gall with Avista stated that he thought that size of the turbines (MW) in the chart looked large relative to what is plausible and realistic for development in the region.

Kathleen Newman with Oregonians for Renewable Energy Progress asked if there is a capacity factor assumed in the cost. Simmons stated that it is not assumed for the capital cost estimate, but the capacity factor is figured into the levelized cost estimate.

Fred Heutte with the Northwest Energy Coalition pointed out that eGRID national data shows that the Northeast (New England) and the Northwest have the highest operating capacity factors in the country. So, even though the data related to combined cycle capabilities appear low in the Northwest, the figures are higher than those found in other regions in the country.

Heutte asked what the elevation de-rate is between, for example, sea level and Wyoming. Simmons said that there is a conversion used per foot of elevation. Gall asked Simmons to include the conversion information in a document, as well as information for water cooling versus air cooling. The group

Generating Resources Advisory Committee Meeting

October 16, 2013

discussed variations to include, such as seasonal variations. Simmons stated that the chart assumes the Boardman plant as a reference, which isn't at sea level or too high in elevation.

Rob Petty with the Bonneville Power Administration asked about what the budget includes in the plant's price in the chart. Simmons answered that it included "bare bone" overnight costs, but not owners' costs. He also noted that the costs on the chart are on the low-side. In later charts the full overnight capital cost estimate is shown.

Non-Adjusted Budget Price by Plant Size, Exhibit of Economy Scale

Simmons explained that the respective slide showed the output of certain manufacturers in regards to megawatts and dollars per kilowatt. The manufacturers include Siemens SCC6-8000H, Mitsubishi MPCP1, Alstrom KA26-1 and GE Flex FE50. Simmons noted that the GE Flex FE50 is the largest unit and has the least cost in terms of dollars per kilowatt unit, showing economies of scale

Jeff King, a contractor from J.C. King & Associates, commented that some of the plants are "vaporware." He wondered if Simmons had thoughts about taking into consideration the fact that some vendors tend to announce a machine before a prototype is available and choosing a representative product. Simmons said that this is a good point and asked for feedback from the GRAC members.

Simmons reviewed the information on the respective slide, as well as the listed manufacturers' start times. Chris Roberts with CR & Associates asked how the Council will incorporate these figures in the Power Plan. Simmons stated that the GRAC will utilize cost and performance data from many sources; which will be normalized to define a CCCT reference plant.

Brown asked if the GE Flex FE50 figure is for the gas turbine CCCT or the entire plant. Simmons stated that the data doesn't specify this information.

CCCT Cost Estimates in 2012 \$

Simmons stated that the respective slide's chart shows data about cost estimates and year. The plots on the graph show the Council's Sixth Plan forecast, E3 Advanced, E3 Basic, EIA Advanced, EIA Conventional, GTW Advanced, Langley Gulch, Carty Generation Station and the Lodi Energy Center cost estimates. Simmons shared that the Lodi Energy Center is similar to the Langley Gulch unit. He noted that the E3 data came from a report created for the World Energy Council in 2012 and that the EIA data came from a report released in 2013.

Advanced CCCT Characteristics

Simmons stated that the information in the respective slide came from E3 and the U.S. Energy Information Administration (EIA). He said that E3 assumed a G- or H-class for the advanced cycle with a 1-by-1 configuration, wet cooling and duct-firing augmentation. He noted that the 2010 dollars were translated to 2012 dollars and that E3 included "All In Costs" and "Overnight Capital Costs."

Simmons explained that the EIA assumed an H-class with a 1-by-1 configuration, wet cooling and duct firing augmentation. He stated that he translated costs related to an average U.S. location that's similar

Generating Resources Advisory Committee Meeting

October 16, 2013

to Boardman, OR, which included an adjustment for labor costs. The group then had a discussion about the costs included in the reports, such as owner's costs, and the assumptions made.

Vijay Satyal with the Oregon Department of Energy asked about the lack of geological considerations. Simmons stated that the GRAC made assumptions about locations along the pipelines.

Recent CCCT Projects

Simmons referred to the respective slide, which offered information about three projects, the years in service, technologies used, capacity, costs and adjustments. The projects include the Langley Gulch plant, Lodi Energy Center in California and the Carty Generating Station. Simmons noted that the Lodi Energy Center does not have duct firing, unlike Langley Gulch, and that adjustment costs included location costs and elevation.

Preliminary CCCT Reference Plant

Simmons shared that a decision needs to be made about whether or not the GRAC should assume an H-class for the reference plant or a more advanced natural gas-fired CCCT. He stated that like the Sixth Plan, the preliminary assumption is a 1-by-1 configuration, 470-megawatt capacity with a 25-megawatt duct firing capability, DLN and catalytic control of NO_x, evaporative/wet cooling, with overnight capital cost of \$1,051 per kilowatt.

Keith Knitter with the Grant County PUD asked if there are multiple reference plants. Gall added that it would be helpful to document at least two different plants. Simmons replied that the addition of plants would call for more complex modeling but it could be done.

Michael Deen with the Public Power Council asked about the operation benefits between older technologies and more advanced technologies. Simmons answered that plants with advanced technologies are going to be more efficient and have potentially faster ramp rates. Deen noted that the advanced technological costs should be reflected in the data. Simmons replied that the advanced technologies aren't necessarily more expensive.

Heutte asked if there are cycling limitations. Simmons stated that this is a good point to consider. Heutte shared findings that he read about in reports. King added that it's also important to consider the variable cost of operations and combined cycle plants. Deen said that Portland General Electric may be a good resource for some of the information that the GRAC may need, given their recent experience.

Knitter stated that the Grant PUD studied an F-class and found that it could take "reserves off the river and have the plant carry the reserves," which could offer more flexibility. After Simmons asked about other factors that the Grant PUD observed, Knitter replied that they looked at ways to keep the plant operational and the river healthy.

Mike Hoffman with the Pacific Northwest National Laboratory stated that it may be good to consider variable O&M costs in response to wind.

Generating Resources Advisory Committee Meeting

October 16, 2013

CCCT Environmental

After a short break, Simmons went onto the respective slide, stating that environmental factors included the cost of emission controls, which are assumed and internalized as part of the overall capital costs. He stated that also considered are water-related costs, including wastewater and solid compliance, which are included in the O&M estimate.

Rick Sterling with the Idaho Public Utilities Commission, Knitter, Gall and Satyal had a short discussion about the costs associated with wet and dry cooling. Simmons shared that a low percentage of units are dry-cooled. Knitter pointed out that Centralia is wet-cooled. According to Brown, Carty is wet-cooled. A suggestion was made that the Council look at dry-cooling as an option for a reference plant.

Satyal shared that the EPA is coming out with an updated set of water intake and discharge rules, and added that it is good to keep this in mind for the reference plant.

CCCT O&M Costs

Simmons reviewed the respective slide, sharing information sourced from the EIA, E3 and the Council's Sixth Plan. He pointed out the variation in numbers, particularly in the EIA's numbers.

Gall asked about the costs of capital improvements and the transportation of fuel. Simmons replied that these are part of the fixed O&M. King stated that the costs are considered separately within fixed O&M

Emissions

Simmons reviewed the EIA's emission assumptions regarding NO_x, SO₂ and CO₂ as he referred to the respective slide.

Heutte pointed out the controversy surrounding emission generation throughout the whole production chain and asked how GRAC's analysis will include this. Simmons stated that this may be included in the production lifecycle of natural gas. Heutte added that there are data gaps in this area.

Greg Mendonca with PNGC Power asked about the lifecycle of drilling, producing gas and its use in a plant, and how the reference plant addresses these items. Simmons stated that the reference plant could separate this data, adding that this data wasn't included in the past plan. King mentioned that the Council did add this information in the Fourth or Fifth Power Plan, but isn't sure why it isn't in the Sixth Plan.

Heutte brought up methane and CO₂ losses at the well site. He shared that in regards to CO₂ valuation for different resources, experts are getting closer to getting a good idea about emissions at the beginning of the production cycle.

Simmons pointed out that one of the considerations to include are the locations that the gas comes from for use in the Northwest. He shared that the NW imports a substantial amount from Canada and the rest comes from the Rockies.

Potential Federal Legislation

Referring to the respective slide, Charles shared that in September 2013, the EPA re-proposed the New Source Performance Standard as part of President Obama's Climate Action Plan, which aims at reducing power plant emissions. The main concern is for coal plants, but there are some standards for natural gas-fired turbines. She stated that plants greater than 250 megawatts would need to meet the standard of 1,000 pounds of CO₂ per megawatt hours and that turbines between 73 and 250 megawatts would need to meet a standard of 1,100 pounds of CO₂ per megawatt hours. Charles explained that the standards only apply to new projects as existing projects are exempt and there is an explicit exemption for simple-cycle turbines. She then added that the standards may take effect next year, pending the approval process.

State Emission Performance Standards (EPS)

Charles pointed out that Washington and Oregon State Emission Performance Standards (EPSs) are generally consistent with the proposed federal standards. King asked if the figures represented annual averages. Charles replied that they do.

CO₂ Production of Combined-Cycle Technologies

King reviewed the respective slide and mentioned the technologies used for the Council's Power Plans and ones that are considered "State of the Art." He stated that the Fifth Plan's representative plant used a GE 207FA in a 2-by-1 F-class plant. The Sixth Plan used a Mitsubishi 501 G with a 1-by-1 G-class plant. The State of the Art—High Efficiency case used a GE 107H 1-by-1 H-class plant (like the Inland Empire Plant). The State of the Art—High Efficiency plant used a Siemens SCC6-5000F Flex Plant 30, like the Lodi Energy Center.

King noted that the CO₂ production figures in the table are only for the plant as it operates at the base-load capacity. He stated that adjustments to take into consideration include the heat rate and gas supply emissions as they apply to related CO₂ standards. King pointed out that efficiencies have increased with the development of technology. He stated that he is not sure why the Flex Plant is less efficient before discussing the heat rate versus CO₂ production listed on the slide. Simmons and King noted that the plants on the table are currently in operation.

Dispatch for Natural Gas-Fired Power

Simmons, referring to the respective slide, asked how natural gas costs are accounted for when bidding into the market: "Is dispatch based on the full natural gas cost—commodity and pipeline charges—or just on variable or commodity cost?"

Gall explained that Avista approaches this by using the AURORAxmp model for combined cycles. For peaking units, since most don't have fixed pipeline capacity, Avista includes, for example, a reservation charge.

Simmons shared that one of the goals is to learn how different plants determine natural gas costs in relation to the different variables. He stated that assumptions include pipeline charges in relation to the fixed and dispatched costs, the manner that plants get their gas and the pipelines used. Phil DeVol with

October 16, 2013

Idaho Power shared that it includes commodity and pipeline charges in the dispatch logic for combined cycle and peaking units.

Deen stated that the “generalizations are nice,” but specific information is better in the dispatch logic if GRAC is modeling 20 units. He noted that figures that are good to report include variable costs and diminishing returns. Simmons stated that past information included EIA data.

Next Steps

Simmons asked for input and feedback from the GRAC members regarding the assumptions so they can finalize the references plants and include information about size, technology, capacity and overnight capital costs.

Williams asked about how AURORA builds and treats different plants, and takes into account the minimum up and down times. Gall replied that it can’t model real flexibility. Simmons added that this type of modeling may be available in more advanced units. Heutte shared that this type of modeling is a feature that one may find in a program. Deen stated that a correct operating range and a heat range curve could address help Williams’ concern.

Newman asked how the decision was made about wet versus dry cooling in the modeling. Simmons replied that reference plant reflects the most likely outcomes in the Northwest.

Simmons stated that they will revisit the topic of CCCTs in the next GRAC meeting in January 2014.

Price Forecasts

Presenter: Steve Simmons, Northwest Power and Conservation Council

Henry Hub Monthly Prices, Constant 2012 Dollars

Simmons stated that Massoud Jourabchi is the Council’s natural gas analyst. Since Jourabchi is out of the country, Simmons will highlight some of the information gathered.

Simmons pointed out that the date in the respective slide goes back to January 1989 so one can see the variability of gas prices, something to remember when looking at forecasts. He shared that factors that have influenced gas prices include hurricanes and economic recessions.

What a Difference a Year Can Make; June 11, 2012: Prices in Low \$2 Range

Referring to the respective slide, Simmons shared that the data shows that gas prices in June 2012 were in the low \$2 range. He noted that the AECO-C Hub, for example, was at \$1.66—a historically low price.

By April 2013, Prices Were Over \$4

Simmons pointed out that the graph in the respective slide shows how prices jumped to over \$4 by April 2013.

After a question about the 2013 average price, Heutte stated that the average price was about \$3.60 and is currently about \$3.80. He said that the Alberta, Canada gas prices (AECO) are generally low and that there is some exporting out of the Northeast into Canada and the western parts of the U.S., which is significantly changing how the big pipeline networks are being used and shifting prices. He shared that consequently, Henry Hub prices, which have been considered the benchmark for almost the last 20 years, are now seeing significant dynamic deviations. Heutte said that the changes will be ongoing because the production coming out of the Marcellus region in the Northeast is so large that it will serve as an export region for the indefinite future, which will influence future forecasts. Simmons added that LNG exports may also cause changes.

Heutte shared that demand factors to consider include exports from northern B.C. and the Gulf, electric and gas vehicles, industrial demand and new power plants. He stated that he believes that demand factors will be an important consideration in the next three to six years.

Simmons asked Heutte about Marcellus-related demand. Heutte stated that demand for conventional forms of energy is forecasted to decrease. He added that production zones in Canada are moving west into the Alberta and B.C. areas, but Canadian production overall is “basically flat.” Heutte stated that while demand is slightly increasing, it is undercut by the production coming out of Marcellus. He shared that he’s read studies that discuss the shift in demand for natural gas, such as demand moving from the Gulf Coast to the Northeast. Heutte stated that the pricing dynamics affect the Northwest because “we’re competing with the East for Canadian gas.”

Long-Term Perspective

Simmons stated that the respective slide is a summary from the ICF Gas Market Outlook about projected Henry Hub gas prices and price trends. The dates on the graph range between 2005 and 2035. He noted that in 2020, gas prices are expected to stabilize and around 2030, nuclear plants will retire.

Heutte shared that the Natural Gas Advisory Committee is having a “robust” discussion about the prediction of gas prices. He explained that shale gas is different than conventional gas, as shale production is relatively quick. Heutte stated that the current debate is about the decline rates, as well as the need for new production and what that does to the cost. According to Heutte, there is plenty of shale and tight sands, so there’s a question about how these factors affect the costs. Heutte stated that he thinks that the market is “under the real costs.”

Hoffman asked if the cost of drilling for gas skews the market. Heutte said that it doesn’t necessarily skew the market, but it changes the “mix.” Heutte noted that dry gas areas have decreased drilling because they’re low on funds, and that the “liquids” market is strong because of good oil prices and the potential for high profits. This “mix,” like oil and gas prices, will change over time, according to Heutte.

ICF Projection for Production and Demand for Natural Gas

In the respective slide, Simmons pointed out the flat levels of demand for natural gas in the residential, commercial and industrial sectors. Demand in the power sector is expected to increase, as well demand

in LNG exports. In regards to production, Simmons noted that shale production is expected to increase over conventional forms of energy.

Newman asked Heutte about risk factors due to regulation in regards to fracking. Heutte stated that any type of drilling is going to have an impact on air and water. He said that the real question to consider is about the impact to the price. Heutte said that from a Green Completion approach, the costs will increase a bit. Therefore, regulatory considerations won't have that much of an impact on shale production.

Jimmy Lindsay with the Renewable Northwest Project asked if transportation demand is represented in the respective slide. Simmons stated that it is not. Mendonca stated that transportation may be included in the "Other" category. Deen commented that forecasts may consider transportation to shift from gas power to electricity, so it would possibly go under the "Power" category.

Proposed Preliminary Forecast and Comparison of 6th and Proposed Preliminary Seventh Power Plan Forecast of Natural Gas Prices

In the respective slides, Simmons pointed out the differences in forecasts between the Council's Sixth Power Plan and the preliminary Seventh Power Plan forecast in regards to natural gas prices. He noted that the proposed Seventh Power Plan's "medium" line is similar to the Sixth Power Plan's "high" line.

Gall and Simmons discussed the ranges represented in the graph and how they differ from forecasts made by other entities. Simmons stated that the "low" forecast on the graph for the preliminary Seventh Power Plan forecast is partly due to the expected production of shale.

Heutte stated that he disagreed with the information in the graph because the forecast assumes that future production will be as strong as current production. He shared that he thinks that costs will increase, especially since the costs reflected are below production costs, which won't make the costs sustainable. Heutte said that he thinks that the preliminary Seventh Power Plan's "medium" forecast on the graph should be the "low, but that the high range is reasonable. He noted that well production data that he's read from the USGF and other sources make him believe that that \$4 prices will not continue through two more decades. Simmons noted that these forecasts are developed with advice and expertise from the Council's Natural Gas Advisory Committee.

Deen stated that it would be helpful to have more information regarding short-term price forecasts. Heutte commented that it is difficult to create an accurate or reliable forward curve because of the market's unpredictability.

Electric Price Forecast

Referring to the respective slide, Simmons shared that the upcoming wholesale electric price forecast, which may be published in March 2014, will include new hydro data parameters (80 year data instead of the previous 70 year dataset), the most recent fuel forecasts, updated transmission links, and updated CA Cap and Trade modeling assumptions. He stated that the forecast will also incorporate generating

October 16, 2013

resource additions across WECC, new RPS forecasts for the Pacific Northwest, and new solar PV, natural gas CCCT, and single-cycle cost estimates.

Hoffman asked if the forecast will include new hydro forecasts on river flows. Simmons replied that the Council uses an 80-year history of river-related data to complete its outlook.

Utility Scale Solar PV Cost

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

Outline

After the lunch break, Simmons reconvened the GRAC meeting and reviewed the outline for the next presentation on the respective slide. Topic items included a summarization of the June 20, 2013 GRAC meeting, new capital cost information, proposed capital costs, the O&M forecast and revised performance capacity factors.

GRAC Meeting 1 (Three Slides)

Referring to the first respective slide, Simmons highlighted some of news articles about solar energy. Articles discussed topics such as:

- Rapid growth in solar development because of solar initiatives like federal tax credits, the Department of Energy's SunShot program and state Renewable Portfolio Standards.
- An increase in solar cell efficiency with a decline in installation costs.
- Solar PV manufacturer bankruptcies and employee layoffs.
- Utility rate-making and net metering controversies.

In the second respective slide, Simmons reviewed "recent cost report summaries." Reports came from the following sources:

- Energy Environment Economics (E3): "Cost and Performance Review of Generation Technologies for WECC" (October 2012)
- U.S. Energy Information Administration (EIA): "Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants AEO2013" (April 2013)
- Lawrence Berkeley National Laboratory (LBNL): "Tracing the Sun V – An Historical Summary of the Installed Price of PV in the U.S. 1998-2011"
- Solar Electric Power Association: "Centralized Solar Projects Update Bulletin – Q1 2013"

In the third respective slide, Simmons reviewed the proposed utility scale PV reference plant with cost estimates and projections. He stated that the reference plant was a 20-megawatt AC plant that used crystalline modules mounted on single-axis trackers and had a three-year development cycle. Simmons stated that the cost estimates came from recent cost reports and projects, and that the initial overnight

October 16, 2013

capital cost estimate for construction declined from \$4,270 per kilowatt AC in 2012 to \$2,888 per kilowatt AC by 2020 and \$2,525 per kilowatt AC by 2025.

Galen Barbose with the Lawrence Berkeley National Laboratory stated that LBL uses the reported AC rating for this type of system, which is based on the rated capacity of the inverter. He shared that the LBL doesn't apply a standard de-rate factor as it uses the rated inverter power rating. Barbose added that Mark Bolinger and Samantha Weaver recently released a publication about the existing plants that uses both AC and DC ratings ([*Utility-Scale Solar 2012: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States*](#)).

Simmons stated that his figures represent those reported by the authors. King added that the report that Barbose referred to shows a trend regarding over sizing the array relative to the inverter in order to yield a higher capacity factor. Thad Roth with the Energy Trust of Oregon shared that he's seen the same engineering design. Heutte stated that he has also read about findings related oversized panels being more economical and efficient.

Preliminary Solar PV Utility Scale Capital Costs (\$/kW AC) for 20 MW Plant

Referring to the graph on the respective slide, Simmons stated that the figures are the preliminary cost numbers reported in the June 2013 GRAC. He noted that the red line represents the proposed reference plant, which has a computed median of \$4,270 per kilowatt AC.

New Solar Information (Two Slides)

In the first respective slide, Simmons mentioned that a number of low-priced power purchase agreements were recently announced and that many of the announcements came out of California municipals. He observed that there seems to be a "sweet spot" for projects around 20 megawatts, which may be due to the cost of land, environmental siting, transmission or integration. Simmons asked the group about the required land size for such a plant. Hoffman replied that he believes that it's an acre per megawatt, but others in the group stated that it may be 5 or 6 acres per megawatt.

Heutte commented that in the Bolinger report, the authors noted that as plants get larger, they don't get cheaper because of environmental constraints and land costs. He agreed that 20 megawatts is a popular plant size.

Simmons shared that the city of Palo Alto in California has three projects starting in 2017 in the Central Valley and the southern part of the state at \$69 per megawatt hour. He stated that the plants will be built on distressed agricultural land and will range between 20 and 40 megawatts. In response to Mendonca's questions, Simmons stated that the prices are levelized.

Heutte mentioned that the Bolinger report included a chapter on power purchase agreements (PPAs) because many purchases have bundled RECs as part of the sale. He noted that the report stated that PPAs also include seasonal pricing.

Generating Resources Advisory Committee Meeting

October 16, 2013

Simmons then reviewed the plant that the city of Roseville plans to build, as well as the two PV projects that Riverside Public Utilities has planned. He pointed out the projects are around \$70 per megawatt hour.

David Clement with Seattle City Light asked about the discount rate since the prices are levelized costs. He also wondered if the prices shown are the costs after tax credits and incentives. Simmons replied that the costs on the slide are the prices after tax credits, but offhand he doesn't know what the discount rate is but it can be looked up in the cost model. Heutte noted that Bolinger report has flat, nominal rates, so they're not indexed and would decline in cost.

Referring to the second respective slide, Simmons highlighted some facts that he learned from the Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory report on solar PV costs:

- Crystalline silicon systems, which the GRAC assumes for the reference plant, are converging with thin film systems in regards to cost.
- There is a large variation in project costs in relation to system configuration, size and geographic location.
- O&M estimates are between \$20 and \$40 per kilowatt year.

Roberts asked if the O&M estimates are inclusive of inverter replacements. Simmons stated that they are.

New Capital Cost Estimate for Solar PV Reference Plant

The respective slide that Simmons showed demonstrated that the reference plant will use a 20-megawatt crystalline single-axis tracker. He noted that the plant's starting point is 2012 and that data related to costs comes from reports published by the EIA, E3, LBNL and SEPA.

Simmons stated that the calculated cost estimates for the 2016 Palo Alto PPA projects range between \$1,908 and \$2,460 per kilowatt AC in 2012 dollars. He noted that the range in price is due to a range of assumptions for the return in equity.

For the reference plant, Simmons said that he used a forward curve through the high case and followed the E3 learning curve estimate.

David Nightingale with the Washington Utilities and Transportation Commission asked about the cost efficiency of a single-axis tracker on a commercial scale compared to its fixed counterpart. Simmons stated that the reference plant uses a single-axis tracker because it is the most common option that plants use.

According to Heutte, it is also important to consider change over time and other factors. Simmons added that there isn't a clear-cut cost differential between single-axis trackers and fixed systems. Gall asked if this topic was something that the GRAC could study.

October 16, 2013

Phil Obenchain with PacifiCorp commented on over-loading the inverters with fixed system so they act similarly to a tracking system. Heutte added that there are studies about the effects of the different films used in different geographic locations because, for example, the data that comes out of the southwestern U.S. may not accurately reflect the results that may occur in the Northwest.

Tomás Morrissey with the Pacific Northwest Utilities Conference Committee, Simmons and Gall discussed the capital costs and the costs included in the reference plant. King reminded the group that the tax credits are not included in construction costs because they're included in the levelized costs.

Solar PV Utility Scale Capital Cost Estimates & Projections

Referring to the respective slide, Simmons noted what the different lines on the graph represent. The date range on the X-axis begins in 2010 and ends in 2032, and the Y-axis shows dollars per kilowatt AC in 2012 dollars. Simmons pointed out that the curve of the proposed Seventh Plan reference plant is similar to the E3 curve but at a lower cost value.

The slide listed the following estimates and projections:

- 2012: \$4,066 per kilowatt AC
- 2015: \$2,794 per kilowatt AC
- 2020: \$2,224 per kilowatt AC

Nightingale asked why Simmons used the “high” number. Simmons stated that there was no real reason for it and was open to suggestions. Nightingale suggested using the middle number.

Greg Nothstien with the Washington State Department of Commerce asked about the short-term impact on tariffs. Simmons replied that some costs are starting to level off.

Simmons explained that the graph included high and low projections for the Palo Alto project and the LBNL Analyst Projection so the GRAC members could see the variation in prices.

King and Simmons had a short discussion about the Picture Rocks project. Simmons stated that he thinks the project near the Boise Airport was canceled. Sterling confirmed this fact, but isn't sure why the cancellation happened.

Deen brought up his concern about the wide range of the figures on the graph and how it affects the portfolio. Mendonca added that he shared Deen's concern and said that he is also concerned about the volatility in capital costs.

Newman asked what the drawbacks would be of including national data on utility-scale PV projects in the Council's data to obtain more accurate projections. Simmons replied that the Council is trying to focus on projects within the Northwest for its data.

Simmons stated that it's difficult to get good details regarding cost information and pointed out that more information will become available as more projects progress.

October 16, 2013

Simmons asked Barbose for suggestions about how to deal with the variation in capital costs. Barbose replied that he doesn't have any particular suggestions because it's difficult to isolate the causes of variations. He shared that going with mid-range information may be the best thing to do.

Heutte suggested that individuals consider the current cost and use the mid-range of the data provided. He stated that he thinks that a lot more information will be available next fall for the Seventh Plan, which will cause a "dynamic situation" in regards to PV because of the new data. He explained that it is important to consider the future and experience curves, and provided some information about the history of experience curve research. In regards to historical trends, Heutte stated that he thinks that solar PV prices will go down 20 percent for every doubling in the global market. He suggested re-examining the learning rate as it relates to global market saturation since solar PV learning curve rates tend to be consistent and robust at 20 percent. Charles stated that Heutte's report about this topic is posted on the GRAC website.

Cost Estimate for Solar PV Referent Plant

Simmons referred to the respective slide, noting the overnight capital costs of the solar PV reference plant. He reviewed the O&M from the EIA and stated that the integration cost is \$1.15 per megawatt hour, based on the BPA's 2012/2013 rate case.

Kugel mentioned the 14/15 rate case update. Lindsay added that the costs should fall between 5 and 15 percent.

Deen asked about the BPA number since it has a small level of penetration, and wondered if there were California experiences that the GRAC could review. Simmons asked the meeting participants if they knew more about integration cost trends. Barbose stated that there are some summary documents available.

Brown pointed out that the BPA's solar integration costs and wind integration costs don't take into account the day-ahead and hour-ahead integration costs.

Sterling shared that Idaho Power just started a solar integration study.

Heutte stated that the \$1.15 figure on the slide represents a limited market for a short term, but that the GRAC had to start somewhere. He asserted that, going forward, it's important to ask the right questions.

Robertson offered a perspective on capital costs. He stated that Green Tech Media and the Solar Energy Industries Association reported in the quarterly market update that the main cost in utility-scale plants in 2013 was \$2.10 DC. He shared that cost reduction work by the Department of Energy, manufacturers and contractors help drive down the costs of separate individual components, and that the proposed goal is the buck-a-watt installed in DC-terms in 2020. Simmons stated that this is an important goal to remember for the future to see how it works out. Robertson pointed out that the GTM costs in the report are before incentives for completed projects in each quarter.

Since the Last GRAC Meeting...

Referring to the respective slide, Charles stated that since the last GRAC meeting, Council staff:

- Defined the Council's approach to solar capacity factors.
- Updated the capacity factors for a single-axis tracker, 20-megawatt AC project for 16 sites.
- Added capacity factors for a fixed-module (ground mounted), 20-megawatt AC project for 16 sites.

Configuration Trends

On the respective slide, Charles referred to the September 2013 LBNL report about the cost, performance and price trends of utility-scale solar. She stated that the report found that trackers tend to yield a higher capacity factor of up to 20 percent over fixed modules. She also stated that the report found that the majority of trackers are single-axis as opposed to dual-axis, as their costs don't outweigh the 10 percent increase in generation.

Capacity Factor – Council

As she referred to the respective slide, Charles recognized that there are different ways to define the capacity factor for a solar plant and shared that the Council's approach to defining it is in terms of AC-AC- the annual generation (kilowatt hours AC) divided by the system rating (kilowatt AC) divided by 8,760 (the hours in a year):

$$\text{Capacity Factor} = \text{Annual generation (kWh AC)} \div \text{System rating (kw AC)} \div 8,760 \text{ (hours/year)}$$

This is a different approach than was presented at the last GRAC meeting, so Charles highlighted the differences and reasoning. Charles stated that the Council used AC (at the connection to the power grid, the power has already gone through the inverter where it has been converted from DC to AC) because it's simpler to compare against other resources. She also noted that the Council considers a solar capacity factor as the average over the lifetime of a plant (last time we only looked at first year capacity factors), including a 0.5 percent annual degradation and a 25-year life.

Modeling Assumptions – 1

Charles noted that the respective slide shows the NREL System Advisor Model (SAM) and the modeling assumptions used to calculate the performance of a solar PV system for the reference plant (20 MW AC, single-axis tracking system). The information on the slide shows the 0.5 percent degradation and a 25-year plant life.

Utility-Scale Solar PV Performance (Single-Axis Tracking System)

Charles, referring to the respective slide, shared the capacity factors derived from the SAM model for 16 sites Council staff selected across WECC (each corresponding to an AURORA load resource area). The table listed six sites within the Pacific Northwest with capacity factors that range between 21 and 25 percent AC-to-AC. She noted that these capacity factors are about two percent lower than what was

October 16, 2013

presented at the last GRAC meeting, mainly due to the change in representing capacity factor as an average over the entire plant life rather than the first year.

Morrissey asked about the inclusion of smaller plants and suggested examining available capacity factor data for small plants may be insightful. Charles replied that smaller plants are not currently represented in the performance evaluation, but that based on the discussion today, staff may be adding a second reference plant that has a smaller installed capacity (maybe 5 MW AC).

Nightingale stated that the Washington and Oregon resource areas may be misleading because anything north of Medford, OR is going to be cloudier. King replied that the Council was looking at utility-scale installations, so it wouldn't have the same constraints as other types of installations. King, Gall, Charles, Simmons and Nightingale had a short discussion about what was considered as western Washington and Oregon, the definition of geographic locations in the Northwest and transmission constraints.

Heutte commented about populations versus solar resources. He said that 90 percent of Oregon is "good for solar," unlike wind, and there is a lot of flexibility in regards to utility-scale installations.

Nightingale asked if it was too late to add locations to the table, like Centralia, WA. Charles said that it is not too late, and that in fact she had run the model using more urban areas (Portland, Seattle, Missoula, etc.) but didn't have the output on hand to show.

Lindsay asked if the capacity factors included oversized panels. Charles said they did not, that the idea of using oversized arrays is somewhat new. Lindsay then asked if the Fresno capacity factors were used for the levelized cost calculations. Simmons replied that he used a range that he got from southern California and Fresno.

Hoffman asked about PV remaining in the region, transmission constraints and market impacts. King replied that the Council defined the market definition in AURORA to have a Northwest-west side and a Northwest-east side. He stated that the Council has considered adding other geographic locations.

Heutte shared that there are two studies that review the interactions between the addition of solar and what happens on the grid by the year 2020. King then explained how the Council uses the data from the models.

Single-Axis Tracker: Monthly Annual Energy (MWh)

Charles, referring to the respective slide, explained that the graphs showed the shapes of solar PV based on the monthly energy output for the first year of operation for the locations listed in the previous slide. She stated that information was derived from the NREL model. She noted that the SAM model uses a long-term average of historical weather files to derive twelve "typical" months; they are not consecutive months in one given year. This helps explain the irregularities in the shapes that one may notice (e.g. Tucson).

October 16, 2013

Charles pointed out that the regions in the Pacific Northwest tend to have a clear peak with lower output, while the desert Southwest has a higher output and less of a pronounced peak.

Nightingale commented that in the Southwest, “they get a lot of spring and early summer production,” but the Northwest “doesn’t need that because of the hydro runoff.” However, he noted, there is a peak in late July, which “is a good time to peak.”

Modeling Assumptions – 2

Charles stated that she ran the model again with the same assumptions, but this time for a fixed-ground mount system (not a tracker).

Utility-Scale Solar PV Performance (Fixed-Ground Mount System)

Charles again showed a table with the capacity factors for all 16 locations for the fixed-mount solar PV system. She pointed out that the capacity factors in the Northwest are lower than those that used a single-axis tracking system as they range between 16 percent and 19 percent. In general, the capacity factors were about 20 – 30 percent lower than the single-axis tracking system, which is consistent with the findings from the LBNL report.

Fixed-Mount: Monthly Annual Energy (MWh)

Charles observed that the peaks in the graphs on the respective slide aren’t as pronounced in the Northwest areas as they were for single-axis tracking systems. The southwestern states also have a “flatter” output.

Single-Axis Tracker vs. Fixed-Axis (Three Slides)

Charles explained the comparison that she did between single-axis and fixed-axis trackers for each of the 16 sites. In the first respective slide, the comparison shows that capacity factors are up to 20 percent higher for single-axis trackers.

Heutte asked: If the study was done on a diurnal basis, would the trackers show more production in the mornings, evenings or afternoons? Charles replied that she was not sure but could look into it. Newman added that it would be helpful to learn information regarding the orientation of the trackers and their output. Heutte stated that this data would help individuals understand time-of-day rates.

The second and third respective slides show graphs with a side-by-side comparisons of the two technologies at the 16 sites.

Solar Energy Industries Association (SEIA) Map

Charles showed a slide with a map of the U.S., which the Solar Energy Industries Association (SEIA) created in May 2013. The map shows the PV and concentrating solar power projects in operation, construction and development throughout the country. Charles noted that there are a few PV projects in the Northwest and a significant number of projects in the Southwest and Northeast. She shared that the solar insolation in the Northeast is comparable to that found in the Northwest, but that the Northeast employs very strong solar incentives and policies.

October 16, 2013

Charles, Gall, Simmons and Mendonca had a discussion about the megawatt size of the plants in the country and their geographic location.

Gall and King had a short discussion about the peak credits used. Williams commented that BPA found that the peaks and demand varied by month and the hourly loads.

Update on Hydropower Potential Study

Presenter: Gillian Charles, Northwest Power and Conservation Council

Objective

Charles shared, referring to the respective slide, that the Council has not created an updated hydropower supply curve since the Fourth Power Plan, so it's time for a "fresh look." She stated that one of the Council's goals is to contract with a consultant. The consultant would review existing national and regional studies, draw conclusions, find commonalities and make recommendations to the Council regarding the ability to create a new supply curve with the information that exists.

Fourth Power Plan

Charles showed a slide with the Fourth Power Plan's hydropower supply curve.

Hydro Potential in the Power Plans

Charles stated that the respective slide shows the hydropower potential when the Council published each of the previous Power Plans.

Update

Referring to the respective slide, Charles stated that a hydropower subgroup met on September 19, 2013 to discuss the history of the interaction between the Fish and Wildlife and Power Planning divisions of the Council, the possible scope of a hydro-potential contract and the proposed project deliverables.

Proposed Next Steps

As she brought up the respective slide, Charles told the group that Council staff will draft a statement of work and release a request for proposals in November or December 2013. She said that the Council will aim to select a contractor in January 2014, contract the work sometime between February and April 2014 and have conclusions by April or May 2014. Charles stated that the hydropower subgroup will continue its involvement after the Council selects a contractor.

Knitter asked how the Council will look at the incremental portion of hydro. Charles stated that the Council still needs to work out what will be included in the scope.

Nightingale asked if the Council will look at future decommissioned plants for the study. Charles replied that this particular study will not. Obenchain stated that it would be a good idea to include this

Generating Resources Advisory Committee Meeting

October 16, 2013

information. King commented that the Council will likely study coal and hydro plant retirements and upgrades.

As Simmons wrapped up the GRAC meeting, Mark Pengilly with Oregonians for Renewable Energy Progress asked when storage will be part of the plan. Simmons stated that this is likely to happen next year. Hoffman then asked if the GRAC will consider storage on all scales. Simmons said that he wasn't sure about the scope yet.

Newman asked if there will be a discussion about rooftop solar. Simmons stated that there will be. Charles noted that rooftop solar was discussed during the previous GRAC meeting.

In regards to the hydro contractor, Newman asked if there would be no inclusion in projection due to climate change. Hoffman and Mendonca commented on regional climate change. Williams stated that the BPA has done studies on climate change in the Columbia.

Next GRAC Meeting

Simmons stated that the next GRAC meeting is tentatively scheduled for January 2014 and shared that agenda topics will include the preliminary resource evaluation of natural gas-fired peaking and flexibility units, as well as a follow-up on combined cycle technologies.

Simmons then showed the slide "Proposed: Resources to Assess." The resources include natural gas combined cycle, wind, solar PV and natural gas simple cycle and "recip" engine. Charles noted that staff had shown this table to the Council's Power Committee and they had similar questions as the GRAC did as to the placement of a few resources (e.g. new hydro, hydro upgrades, storage). She noted that putting storage in the far right column (long-term potential) was a bit misleading because there are so many different storage technologies that could potentially be in different columns if broken out.

The GRAC meeting adjourned at about 2:45 P.M.