

Generating Resources Advisory Committee Meeting

May 28, 2014

- Meeting Time:** 9:30 A.M. to 2:45 P.M.
- Meeting Location:** Northwest Power and Conservation Council
851 SW 6th Ave.
11th Floor Meeting Room
Portland, OR 97204
- Facilitator:** Steven Simmons and Gillian Charles, Northwest Power and Conservation Council
- Note Taker:** Kyle Gustafson
- Attendees:**
- On-Site*
- Rick Sterling, Idaho PUC
 - Tomás Morrissey, Pacific Northwest Utilities Conference Committee
 - Thad Roth, Energy Trust of Oregon
 - Stefan Brown, Portland General Electric
 - Eddie Abadi, Bonneville Power Administration
 - Fred Heutte, Northwest Energy Coalition
 - Michael O'Brien, Renewable Northwest
 - Paul Dockery, Clatskanie PUD
 - Chelsea Wright, Public
 - Robert Brown, Portland General Electric
 - David Nightingale, WA Utilities and Transportation Commission
 - Gillian Charles, Northwest Power and Conservation Council
 - Steve Simmons, Northwest Power and Conservation Council
 - Charlie Black, Northwest Power and Conservation Council
 - Jeff King, J.C. King and Associates
 - Greg Nothstein, Washington Department of Commerce
 - Jeff Kugel, PNGC Power
 - Erin Erben, Eugene Water and Electric
 - Chris Robertson, Chris Robertson and Associates
 - David Brown, Obsidian Renewables
- Attendees:**
- Via GoToMeeting*
- Mike Hoffman, Pacific Northwest National Laboratory
 - Robert Petty, Bonneville Power Administration
 - James Gall, Avista
 - Kevin O'Meara, Public Power Council
 - Elizabeth Hossner, Puget Sound Energy
 - Russ Schneider, Flathead Electric Cooperative
 - Dave LeVee, Pwrcast
 - Robert Diffely, Bonneville Power Administration
 - Brian Dekiep, Northwest Power and Conservation Council
 - Zac Yanez, Snohomish PUD
 - Tom Kaiserski, Montana Department of Commerce
 - Rick Rozanski, McMinnville Water & Light
 - Jessica Zahnow, Bonneville Power Administration

Welcome and Introductions

Presenter: Steve Simmons, Northwest Power and Conservation Council

Steve Simmons began the Generating Resources Advisory Committee (GRAC) meeting at 9:00 A.M.

The GRAC meeting attendees introduced themselves.

Simmons reviewed the agenda and the role of the GRAC.

Preliminary Assumptions for Natural Gas Peaking Technologies

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

Overview

Simmons reviewed today's discussion on natural gas peaking technologies.

Definitions and Applications of Gas Units

Simmons reviewed definitions of baseload energy, peaking capacity, hydro firming and flexibility. Based on these definitions, Simmons discussed the applications of gas units on the table on slide 4. Simmons explained that this is a preliminary look at how the Council is proposing to divide natural gas-related technologies into categories and how to look at resources for the Seventh Power Plan and asked for comments.

Michael O'Brien noted that the recip, aeroderivative and intercooled all looked the same and wondered if there was anything to distinguish between them. Simmons responded that there are differences in cost, heat rate, and other characteristics, and that we will be talking through those later in the presentation.

In response to a question about advanced CCCT being able to serve a hydro firming function (even though it wouldn't be the primary purpose or investment reason), Simmons said that the idea with the hydro firming category is that it would be a unit that may sit unused for years and only be run during poor hydro years. An advanced CCCT could potentially be used in that way, but in this scenario, in general, it would not be operated for that purpose – we would expect it to serve baseload.

Historical Peaking Plant Additions in the Region (Megawatts)

Gillian Charles reviewed the graph on slide 5 showing the historical additions of natural gas peaking plants in the region. Charles noted a transition from the 1970's and 1980's when frame units were primarily built, to the 2000's when there was more diversity in the technologies to include aeroderivative and reciprocating engine units.

Greg Nothstein with the Washington Department of Commerce asked if some of the older plants in the graph are still in operation. Charles responded that the plants listed on the slide are still operating.

Overnight Capital Cost Assumptions and Normalizations

The Development of Overnight Capital Cost Estimates for the Reference Plant

Charles introduced the next topic, an overview of the methodology used to develop overnight capital cost estimates and to discuss a few of the assumptions and normalizations used that have the potential to significantly affect the outcome of the final overnight capital cost estimates.

As a review, Charles described how the Council develops overnight capital cost estimates for reference plants. Charles said the Council gathers cost-related data—such as pre-construction costs and as-built costs for specific power plants—from several sources including the media, press releases, developer and utility websites, commission filings, utility integrated resource plans (IRPs) and generic reports.

Charles stated the data that the Council gathers is often in different vintages, year-dollars and plant configurations. She said the Council is essentially trying to normalize the data points to the selected reference plant for the Seventh Power Plan.

James Gall with Avista stated his organization acquired a software program for its upcoming IRP that develops capital and O&M cost information based on the type of plant, its location and other factors. He said it also keeps up with market-related information and offers a third party point of view. Gall suggested the software might benefit the Council so it can double-check its numbers regarding costs. He said he'd send Charles an email with more information about the software program.

Charles explained that the data is normalized to common year 2012 dollars (the year-dollar for the Seventh Power Plan), ISO¹ capacity and heat rate values, and a typical configuration for the Pacific Northwest. Once all of data points are normalized, they are plotted on a chart and reviewed for trends and outliers.

Charles briefly reviewed the reference sources on slide 8, noting that the California Energy Commission's latest report was just released and had not yet been included in this round of assumptions.

Some Assumptions May Have a Significant Effect on the Final Estimate of Capital Cost

Charles reiterated that staff was looking for feedback on the assumptions used when normalizing data. Two in particular that can have a significant effect on the final estimate of capital cost are the unit scaling factor and owner's cost assumption.

The unit scaling factor is used to convert the plant configuration of the data points to the reference plant configuration. The more units in a project, the greater the assumed economies of scale due to shared infrastructure costs. For example, for the Seventh Power Plan, the proposed intercooled reference plant is a 2-unit plant configuration, whereas many of the data points are for single unit plant configuration. In order to normalize the single unit intercooled data points to the reference plant, a scaling factor is applied. The preliminary assumption is that single-unit plants cost 15 percent more per kilowatt than multi-unit plants for gas peaking turbines. In contrast, the Sixth Power Plan used a 30%

¹ International Standards Organization

scaling factor based on a NY ISO report. The current assumption of 15% is based on a revision to the report.

Fred Heutte with the Northwest Energy Coalition said the 15 percent-related assumption for the Seventh Power Plan makes sense for larger units. He asked about the assumption for smaller units, including reciprocating engines. Charles responded the 15% assumption is for frame, aeroderivative, and intercooled units. Simmons answered that reciprocating engines are more modular than the other gas peaking units and therefore the scaling factor is not applicable. There is another conversion factor used for combined cycle plants to scale the configuration of gas units and steam units (2x1 vs. 1x1).

The second significant assumption is the application of owner's cost. Charles said that in addition to considering engineering, procurement and construction (EPC) costs, the Council is taking into account project development-, land-, infrastructure- and financing-related costs. Charles stated the Council assumes that owner's costs are not included in preconstruction cost estimates unless specifically noted, so they apply an adjustment factor to include owner's costs in the overnight capital cost estimates. She said that for the Seventh Power Plan, staff is currently assuming the owner's costs are 25 percent of the EPC (the Sixth Power Plan used 12%). She explained that the 25% is more consistent with other generic reports and IRPs.

Elizabeth Hossner with Puget Sound Energy said her agency uses Black & Veatch for its cost estimates. She said a Black & Veatch representative told her agency the owner's costs could range between 20 to 50 percent. Hossner explained that the 20 percent figure is based on an existing brownfield project and the 50 percent figure is a greenfield project. She said Puget Sound Energy uses a 40 percent assumption for owner's costs.

Gall said the software that Avista uses calculated the owner's costs to be 25 to 30 percent for a combined cycle plant.

Draft Seventh Plan Reference Plants and Capital Cost

Proposed Configuration for 7th Plan Reference Plants

Charles reviewed slide 11. She noted that she showed the same table at the last GRAC meeting, but the proposed configuration for the frame unit reference plant is different—it's an F-class frame instead of an E-class frame. She explained that preliminary thinking was to configure gas peaking reference plants to resemble the capacity of Port Westward II (~220 MW), the most recent peaking unit to be developed in the region.

Tomás Morrissey with the Pacific Northwest Utilities Conference Committee (PNUCC) asked if the Council is considering anything smaller than a plant that is around 200 megawatts.

Charles replied that the reference plants listed are the ones that the Council is going to use for now, but they are open to looking at reference plants that have less capacity. Simmons added that for reference plants, the Council is trying to define what a logical plant would be for the region.

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Charlie Black with the Northwest Power and Conservation Council stated the assumptions would go into the Council's portfolio modeling analysis, which offers a regional look.

Stefan Brown with Portland General Electric (PGE) asked if the Council is modeling reciprocating engines as individual units. Simmons replied that they are modeling it as one plant with 12 engines. S. Brown said PGE isn't planning to operate the plant in this manner. Black clarified that the current assumptions on the slide refer to capital costs, not dispatch costs. Brown agreed this was ok.

Properties of Frame Technologies

Charles reviewed the properties and characteristics of frame technologies on slide 12. She pointed out that the information is for single-cycle frame units – not for combined cycle units.

Huette asked for an example of a hydro backup frame. King said the historical operating pattern of the Puget Sound Energy units prior to five years ago are fairly typical of hydro backup frames because they sat idle for years at a time, except during the completion of required air quality tests. He said that when there was a need for energy, the units operated for periods that lasted several days. Huette added that the frame units have had a different operational pattern within the last few years, which he said that he assumes is due to lower gas prices.

Proposed Frame Reference Plant

Charles reviewed slides 13 and 14, describing the proposed frame reference plant configuration and characteristics – single unit 216 MW nominal capacity GE 7F 5-series.

Referring to construction times in the table on slide 14, Charles explained the following terms:

- *Development*: The time between a stated need for a project and the creation of a contract; development time includes feasibility studies, permitting and preliminary engineering.
- *Early construction*: The completion of final engineering, the major equipment is ordered and the site is prepared for interconnections, infrastructure and construction.
- *Committed construction*: The delivery of major equipment, construction is complete and commissioning.

Morrissey asked if the plants are capable of running dual fuel.

Charles replied that some are, but the Council is assuming single fuel for cost purposes.

Hossner asked if the capital cost (\$1,000 per kilowatt) includes the owner's cost.

Charles answered that it does include the owner's cost.

Hossner said Puget Sound Energy estimates a \$837 per kilowatt capital cost figure for a frame unit, which includes the owner's costs. She said the E3 report also lists a lower capital cost.

Gall said Avista's estimates are lower than Puget Sound Energy's estimates. Charles indicated that some of the cost difference may be in the technology modeled, but that she would take these figures into account.

Preliminary Capital Cost Estimates for Frame Technology

Charles discussed the graph on slide 15, displaying the preliminary capital cost estimates for frame technologies. She said the Council does not have any new (past five years) cost estimates for as-built frame units.

Charles stated that there is a clear disconnect between data points observed in the Sixth Plan versus the preliminary estimates for the Seventh Plan, so rather than extend the Sixth Plan curve, the Council decided to start its preliminary capital cost estimates curve at around \$1,000 per kilowatt for the draft Seventh Power Plan. She noted that the disconnect may be the result of using different technologies in the Power Plans – the Sixth Power Plan used an E-class turbine and the preliminary Seventh Plan unit is a more advanced flexible F-class unit.

Dave LeVee with Pwrcast asked if the capital cost includes capital cost-related differences between the owners of the respective plants in regards to cost-to-capital. Simmons replied that they do not, but they do appear in the levelized cost calculations. Charles said they might discuss levelized cost estimates for peaking units during the next GRAC meeting.

Black stated that during his career, the supply and demand of turbines have varied dramatically, affecting market prices and project costs. If there is a big rush on development and GE (for example) gets a big backlog of orders, the price in the primary or secondary market is affected. He asked the meeting attendees if they noticed the same thing.

Hossner said Puget Sound Energy is seeing prices decrease from the 2013 IRP across the board. One reason may be that when gas prices dropped a few years ago, vendors anticipated that demand would increase. However, that did not happen and now there seems to be an oversupply of equipment that is forcing prices down.

Gall said Avista noticed the same thing as Puget Sound Energy. The gas turbine prices in the current IRP will be lower than the last IRP.

King noted that normalizing to market equilibrium is important.

Properties of Aeroderivative Technologies

Charles reviewed the properties and characteristics of aeroderivative technologies on slide 16. Black asked if aeroderivative units are more fragile in regards to duty cycles than frame units, which can run for extended periods of time. King replied that aeroderivative engines are derived from the aerospace, aircraft and marine industries, so weight is very important. The components of the aeroderivative engine are lighter than those of the frame, and they are easier to maintain and perform overhauls on.

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Proposed Aeroderivative Reference Plant

Charles reviewed slides 17 and 18, describing the proposed aeroderivative reference plant configuration and characteristics – four GE LM6000PF SPRINT units of 48 MW nominal capacity each.

Preliminary Capital Cost Estimates for Aeroderivative

Charles explained the graph on slide 19, displaying the preliminary capital cost estimates for aeroderivative technologies. She noted that the preliminary cost curve extends from the Sixth Power Plan line, deviating from it in 2008 when the effect of the recession appears not to have lowered prices as anticipated. The preliminary capital cost estimate for an aeroderivative plant in 2012 is about \$1,270/kw.

Properties of Intercooled Technologies

Charles reviewed the properties and characteristics of intercooled technologies on slide 20. She noted that there are currently no intercooled projects in the Pacific Northwest, but that there are several in the Western Electricity Coordinating Council (WECC) area.

Eddie Abadi with the Bonneville Power Administration (BPA) asked if any manufacturers, other than General Electric (GE), are considering developing the respective technology. Charles answered that she does not know.

Proposed Intercooled Reference Plant

Charles reviewed slides 21 and 22, describing the proposed intercooled reference plant configuration and characteristics – two GE LMS100PB units of 99 MW nominal capacity each.

Rick Sterling with the Idaho PUC asked what the heat rate assumption estimates are regarding location and elevation for the different technologies discussed.

Charles replied that the Council is using the ISO's conditions, so they haven't considered elevation adjustments yet, but they will.

Simmons stated they normalized the combined-cycle technology to the Boardman plant.

Preliminary Capital Cost Estimates for Intercooled Hybrid

Charles explained the graph on slide 23, displaying the preliminary capital cost estimates for intercooled technologies. The preliminary capital cost estimate in 2012 is about \$1,080/kw.

Simmons asked why the "Haynes GS" preconstruction estimates are so high.

Charles answered that Haynes is in Los Angeles, California, and projects in that area tend to be more expensive than those in the Pacific Northwest. She said that even though the project may not be applicable to the GRAC's estimate, it is a data point with useful information.

Reciprocating Engines

Reciprocating Engines for Electric Power Generation

Simmons discussed slides 25 and 26, describing the proposed reciprocating engine characteristics.

S. Brown commented that an advantage of reciprocating engines compared to aeroderivative or frame units is that they have a flat heat rate from “zero to full capacity” per engine.

Recip Cost Information

Simmons reviewed cost information on slide 27 and explained the preliminary estimated capital costs for reciprocating engines on the graph in slide 28.

Russ Schneider with the Flathead Electric Cooperative asked if using 2012 dollars was consistent throughout the Council’s analyses. Simmons said the Council is using 2012 dollars for the Seventh Power Plan.

Hossner asked if there are any drawbacks to reciprocating engines. She said air permitting is an issue that Puget Sound Energy has encountered, as they have had problems getting permits for the engines to run on dual fuel instead of just natural gas.

Simmons replied that they discussed the respective drawbacks during the last GRAC meeting, such as high NOX emissions.

Heutte added that the engines are noisy since they utilize spark compression, so they can’t be in a downtown area.

Recip Proposed Reference Plant

Simmons went over the proposed reference plant in slide 29. He stated he’d have the fixed and variable operation and maintenance (O&M) costs available at the next GRAC meeting. Simmons noted that the shorter economic life of 25 years might be a disadvantage of the respective technology. Simmons also explained that there appeared to be a shorter construction time for the recip (12 months) than the other peaking technologies.

O’Brien asked why the capital costs for the Northwest Energy IRP in the graph on slide 28 are so much higher than the others.

Simmons replied that the Northwest Energy IRP used a different manufacturer—Caterpillar instead of Wärtsilä.

Preliminary Capital Cost Peaking Units

Simmons went over the chart in slide 30, which showed a summary of the peaking technologies and their respective preliminary capital cost estimates.

Brown asked why the first three technologies (Frame, Aero, and Intercooled) on the chart are labeled as “lifecycle,” but Recip is labeled as “new and clean.”

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Simmons answered that they have not normalized the recips based on lifecycle, and he has not seen information regarding degradation. He said the figure is based on a “flat output.”

Next Steps for Peaking Units

Simmons reviewed some of the next steps for peaking units on slide 31.

Natural Gas Combined Cycle Combustion Turbine, Solar PV Utility-Scale, and Reference Plants and Levelized Costs

Presenter: Steve Simmons, Northwest Power and Conservation Council

Simmons noted that both natural gas combined cycle combustion turbine and utility scale solar PV have been discussed fairly extensively at previous GRAC meetings. The purpose of this agenda item is to provide an update on reference plants, capital cost, and levelized cost.

Reference Plants

Simmons reviewed the two combined cycle reference plants on slides 3 and 4. He noted that one reference plant has wet cooling and the other has dry cooling, which is more advanced and efficient.

Referring to the chart on slide 4, Morrissey asked if the build date of the facility was the same as the “Levelized Cost of Energy (2018).” Simmons answered that 2018 is the year when the plant will be in operation.

Solar PV Update

Simmons reviewed the solar pv reference plant on slide 5. He noted that staff was considering an additional solar PV reference plant around 50MW – 100MW capacity, he said they don’t have a lot of information available about large solar PV plants in the Northwest because none have been built to-date larger than 5 MW.

S. Brown asked if utilities are building more plants with single-axis trackers than fixed-axis trackers.

Simmons replied that historically, utilities built more plants with single-axis trackers. He stated some reports show a great variation on capital costs due to factors that aren’t related to the tracker type, so it’s hard to determine a cost difference. Simmons said there is a performance difference, but this factor depends on the plant’s location.

S. Brown asked what the Council is considering in regards to the orientation of the solar panels.

Simmons answered that the Council has not covered this detail yet, but the orientation of the panels would depend on their location.

S. Brown commented that it seems as if a lot more panels do not point directly south.

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In regards to small-scale solar panels (e.g., rooftop panels), Heutte stated, “At least in California, because of the daily load peak issue being different than the peak output...there is some tendency now...to move toward a southwest orientation because of that difference. Because the value is so much greater later in the day... you lose some output, but you gain a little bit on the time.” Heutte added that there are two factors to consider—storage and site economics. He also said land acquisition for a 100-megawatt plant is difficult.

Sterling said Idaho Power is proposing projects that are up to a total of 500 megawatts, but most of the individual projects are 10 or 20 megawatts. He said most of the 20-megawatt plants are not stand-alone facilities, but clusters of 5- or 10-megawatt units. Given the choice, Sterling thinks that most places in the region would choose to build projects greater than 5 megawatts. Simmons noted that originally, staff was considering a 20 megawatts reference plant but that due to conversations with the GRAC had lowered it to 5 megawatts.

Sterling and O’Brien discussed if the 500 megawatts of proposed projects at Idaho Power include general inquiries without firm commitments to build or commitments that are more serious.

Sterling said that those who have made inquiries regarding about 250 megawatts of the power have draft contracts in-hand.

Simmons stated Pacific Power was considering 5-megawatt units, and the GRAC can discuss using a larger plant for a second reference plant.

Sterling said land availability in southern Idaho is not an issue.

Heutte said he thinks they’ll see a staged development in the Northwest that’s different from the development in California, which started out with small projects and then leaped to larger ones for various reasons – Federal credits, California’s RPS. He stated he thinks the Northwest will start out with smaller 20-megawatt projects and then consider bigger ones. There is a lot of land and good solar resource available in SE Oregon and Southern Idaho in particular, but that other issues like transmission access could be barriers to development.

Solar PV Utility Scale Capital Cost Estimates & Projections

Simmons reviewed the capital cost estimates and projections on slide 6. He noted the costs are overnight costs and the kilowatts are AC (alternating current), not DC (direct current). He also highlighted the inclusion of the SunShot Goal of \$1 per watt DC by 2020.

Heutte commented that there is a good chance the SunShot Goal will be met. He said the global market is expanding so fast that prices will continue to decrease. Heutte noted that another issue to think about is the balance of system costs in regards to small-scale solar PV projects.

Simmons noted that the Council’s respective forecast is not fixed as they continue to update it over time.

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Heutte said some solar advocates tend to focus on the costs from the last year or two and use those as the basis for a projection going forward. He stated he disagrees with this projection because one needs to take into account a longer period and market dynamics. Heutte added that it is better to look at 5- or 10-year trends, as he thinks capital costs will dip lower than the costs projected in the respective graph.

LeVee asked if the estimates included any credits or tax benefits, like the 30 percent Investment Tax Credit. Simmons replied that the capital costs in the respective graph are overnight capital costs without any credits or benefits.

Recent Solar PV Power Purchase Agreements

Simmons reviewed recent solar PV power purchase agreements in New Mexico and Texas on slide 7.

Abadi asked if any states, aside from New Mexico, offer production tax credits. Simmons stated he was not sure, but assumes there are. Black commented that the New Mexican tax credit is limited.

S. Brown stated he thinks New Jersey offers similar incentives. Heutte added that Washington state does as well.

LeVee asked if the power purchase agreement (PPA) with El Paso included the average price or if the prices corresponded to the actual hours of production by the solar generation.

Black responded, "They have an additional time-of-production credit that they attribute to this, but this is just the energy price."

Levelized Cost of Energy

Simmons reviewed the calculation and purpose of levelized cost of energy (LCOE) calculations.

Simmons noted that along with assumptions like capital cost, financing costs, O&M costs, fuel costs, emission costs, and utilization, LCOE does adjust for tax incentives.

Simmons reviewed slide 10, noting that there are important factors that go into LCOE based on resource technology type. For solar PV, the primary cost component of LCOE is the capital cost. For natural gas combined cycle, fuel costs are significant cost components of LCOE.

S. Brown asked if the LCOE for solar included integration costs. Simmons replied that it does include an integration cost. S. Brown said the integration cost might be the reason for the difference between the PPA and LCOE costs. Simmons stated that he agreed.

Black asked if the term "integration cost" related to the cost of "interconnection into the grid" or the system balancing cost.

S. Brown replied that it referred to system balancing costs.

Simmons stated he was referring to transmission, or interconnection, costs, but the cost could apply to both interconnection and system balancing costs.

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Heutte noted that the Palo Alto and Austin utilities are public agencies with public agency finance considerations. He said they're both progressive utilities with supportive ratepayers, and could serve as an indication of the direction of the market.

Abadi asked if the respective costs covered connecting to the grid, but not firming and balancing.

Simmons replied that Abadi was correct.

Dockery pointed out that perhaps some PPA costs are lower than published LCOE costs because "they're betting a curve that may not be realistic and they may not actually show up." He added that developers look at manufacturing cost curves for solar and then projecting costs that are much lower, so "they sign a PPA and (do) not have much termination costs."

Heutte stated that while "some part of the expected market, or deals, is not going to turn out," the track record in California is better than expected as the plants are "going in and performing pretty well, especially on the PV side." He discussed some of the solar-related market expectations and said Palo Alto and Austin are good examples of "what you can get if you really push the market."

Chris Robertson of Chris Robertson and Associates commented that the president of SolarWorld USA committed his company to meeting the SunShot goal by 2020 during an OSEA meeting in February 2014. He said SunPower and First Solar are probably going to meet the goal before 2020. Robertson stated that a Portland electrical contractor is offering EPC contracts at "\$1.50 per watt with a 10¢ adder for 10 percent of the plant capacity and battery storage that will integrate the plant. That will firm and balance the plant." He added that he thinks the respective capital costs in the slides are too high and the Council should "include a price vector that hits the 2020 SunShot initiative, particularly for utility-scale plants."

Simmons replied it would be interesting to see what it would take to meet the SunShot goal in regards to module and the balance of plant costs.

In regards to natural gas, Robertson asked if the data included the tax effects for fuel purchases.

Simmons replied that they were for fuel costs.

Robertson asked if the Council was "netting the fuel cost up, or grossing them up, to reflect the tax deduction for fuel costs in those plants."

King replied that the Council treats fuel costs as expenses.

Robertson posed that if the Council wanted to do a more "symmetrical" comparison of solar PV and natural gas, would it not symmetrically compare the gas effect for both types of plants.

King replied that the objective is to "reflect costs as they would pass through to the rate payers. In the real world, fuel costs are expensed, so there is no tax effect" because the tax effects are embedded in the fuel cost estimates.

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In regards to transmission integration costs and system balancing costs, King clarified that the Council does include system balancing costs estimates in the transmission element of MicroFin.

Sterling stated that Idaho Power is in the process of completing a solar integration study, which it expects to complete in about three weeks. He said he heard that PacifiCorp is working on a solar integration study.

Schneider said, referring to the graph on slide 6, he thinks the “proposed” line looks reasonable. He cautioned against “low-price enthusiasm” even though there is a lot of “group think and enthusiasm” in regards to decreasing solar costs, referring to the two data points and the goal under the “proposed” line.

Heutte responded that the projections about decreasing costs are more than just “group think” and the projections are more than guesses. He said there is reputable data that points to lower solar costs in the future. Black said the topic of solar costs lends itself to a scenario analysis for the Seventh Plan. He stated the Council could examine what-ifs regarding the meeting of the SunShot goal and a technological breakthrough in energy storage. He said the purpose of the projections is to be able to prepare for different outcomes that may occur.

Black then commented on how the GRAC develops information for use in the overall Power Plan analysis. He explained how the Council derives its system-balancing costs for the Seventh Plan. He then said it’s important to be consistent about how one creates assumptions instead of “presume the overall costs of integrating, or balancing, the system with or without solar.”

David Nightingale with the Washington Utilities and Transportation Commission said he thinks that completing a scenario analysis is a good idea.

David Brown with Obsidian Renewables said the cost of solar today in Oregon and Idaho for a 10-megawatt project is about \$2.30 per watt (DC) in 2015 dollars. He stated the cost would be lower if more than one project was built per year. D. Brown also noted that solar projects in the Northwest have difficulties securing good financing and finding low costs. He said the cost of solar will never be higher than \$2.30 and its not necessarily due to the panels. He stated that the market has adjusted to a one-time deal and the rate will continue to decrease because PV panels produce so much more energy per square inch than they used to. The more efficient solar panels become, the lower the associated costs are. D. Brown suggested changing the size of the reference plant to 10 or 20 megawatts.

D. Brown and Simmons discussed the cost of solar power and adjusting it AC or DC. They also talked about using 2012 dollars versus 2015 dollars.

D. Brown talked about the cost of power and the amount that property taxes figure into the price.

King said the costs would ultimately go into the Council’s Regional Portfolio Model, which treats capital costs like stochastic variables. He suggested the Council estimate the range of uncertainty for the

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respective costs and think of the costs as a “cost band” because “some of that can be captured in the Council’s analysis.”

Heutte said he thinks that the band will narrow as the solar market grows. He then discussed the variability of associated costs and the demonstration of the narrowing costs in an analysis.

Levelized Cost of Energy: Solar PV Utility Scale

Simmons explained the levelized cost of energy for utility scale solar PV graph on slide 13. He noted that he used the MicroFin model for the graph and an investor-owned utility (IOU) financing assumption.

In response to Black’s questions, Simmons stated the model assumed a 30 percent Investment Tax Credit through 2016 and a 10 percent Investment Tax Credit starting in 2017.

Dockery asked how the Council is monetizing the tax incentives in regards to the “Council with Municipal Financing” line in the respective graph.

Simmons replied that the production tax incentive is in the same category.

King said Congress has not fully funded the incentives, so it may not be realistic to assume that it’s available.

Black said that in other states, like California, there are arrangements so a non-utility developer can take advantage of the Investment Tax Credit and pre-payments that are funded through tax-exempt financing by publically owned facilities.

LeVee commented that when one considers financing costs to be the same as economic costs, it is like comparing apples to oranges. He said that since the two are not the same, there has to be a clear “vision” about if one is considering the “least economic, most efficient way of providing services to customers or whether you’re trying to look at financing costs where you actually—with PPAs or public ownership—have done a shift of risk between different parties and a shifted risk to either the purchaser of the energy through a PPA or through public through risk to the public ownership. It appears that the cost-to-capital goes down or changes, and that is really not the case in economic terms.” LeVee said he thinks they need to address whether they’re trying to do an economic analysis or are “convoluting things by doing risk shifting and perceiving that there is a different cost to capital.”

Simmons replied that the capital costs are expected to decline, which is what the respective graph shows.

King commented that they’ve dealt with the issue LeVee brought up regarding risk shifting affecting financing costs by exclusively assuming IOU financing, which assumes a more consistent allocation of risks. He discussed how the Council dealt with similar issues in the past and talked about risks due to technology characteristics.

Robertson suggested it might be useful to include the Idaho Power IPP levelized costs using the IPP avoided cost strip as a surrogate for the IPP price.

D. Brown stated there are “easily available” municipal finance strategies that can reduce the cost of electricity by 20 percent. He talked about the different financing strategies that could be available to IOUs and about the laws affecting those strategies.

S. Brown asked if a municipal’s cost-to-capital applies since it can’t take advantage of the Investment Tax Credit.

In regards to Simmons’ and S. Brown’s comments, D. Brown said levelized costs can be higher than PPAs when utilities learn from past occurrences and inflate reported capital numbers, or when they add to some of their internal costs for a PPA price when determining the cost of a generating facility.

Levelized Cost of Energy: Natural Gas Combined-Cycle CT

Simmons explained the levelized cost of natural gas combined cycle graph on slide 14. He noted that the figures are based on the Council’s 2013 fuel price forecast.

In response to Black’s question, Simmons said they assumed an 85 percent capacity factor.

Heutte asked about the prices used for low, medium and high fuel sensitivities.

Simmons replied that the Natural Gas Advisory Committee advised on the prices.

Black added that the medium price range is in the mid-\$4.00 range.

Heutte commented that he thinks the prices are unrealistic; he would adjust the high-end costs. He discussed using a “band” for prices, as they fluctuate.

Simmons stated the graph begins in 2020 and has a 30-year outlook.

D. Brown asked how the graph reflects inflation.

Simmons replied that the figures on the graph are in “real” 2012 dollars, which aren’t nominal, so inflation is not reflected. However, one could apply an inflation rate.

Nightingale asked if the Council is going to create scenarios for fossil fuel generating resources.

Simmons responded that the scenarios will be developed with input from the Resource Strategies Advisory Committee (RSAC). Black added that they would include different gas price scenarios and would analyze green house gas scenarios on a portfolio basis.

Levelized Cost of Energy: Solar PV & Natural Gas CCCT

Simmons reviewed the graph on slide 15.

Preliminary Assumptions for Wind Technologies

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

Charles gave an overview of the presentation, which was a first-look at windpower technologies for the draft Seventh Power Plan. She briefly described the current status of wind in the Pacific Northwest, noting that 2012 was a big year in terms of new wind installed but that there has been very little development since.

Current Installed Wind Projects

Charles discussed the map on slide 4. She noted that the wind projects highlighted on the map are in operation.

Charles discussed the drivers of wind development on slide 5, noting that the state renewable portfolio standards (RPS) and Federal and Regional tax credits and incentives were major drivers to date. In addition, wind is an emission-free resource with no associated fuel costs. On Slide 6 Charles reviewed the status of the Production Tax Credit (PTC) and the Investment Tax Credit (ITC). The PTC expired at the end of 2013 and has not yet been extended or renewed. There remains uncertainty if it will be renewed again or if it will go away all together. Charles discussed the status of the regional RPS on slide 7, noting that based on the Council's analysis, the region appears to be compliant through about 2020 with existing committed and planned resources, planned REC procurements, and banked RECs.

Annual and Cumulative Wind Capacity in the Pacific Northwest

Charles explained the wind capacity installed in the Pacific Northwest graph on slide 8. She said that after a big ramp up in development from 2005 to 2012, there has been a marked decline in activity since then. On slide 9, Charles showed a chart of nationwide wind development, which follows a very similar trajectory and pattern as the Pacific Northwest. She noted that the years listed on both charts are when projects entered service.

Charles shared a breakdown of where the wind in the Pacific Northwest is contracted. About 1/3 of the wind installed in the PNW is contracted to California IOUs and public utilities through long term power purchase agreements.

Wind Trends

Simmons discussed trends in wind project cost on slide 11, noting that while overall capital costs have declined significantly since 1980, there has been an increase in capital cost from 2003-2010. On slide 12, he discussed the trends in technology, most significantly the growth of rotor diameter and hub height which lead to increased capacity factors. In terms of project development, with less demand for renewables to meet near-term RPS, independent power producers are having increased difficulty building projects without power purchase agreements.

Simmons reviewed slide 16, showing monthly regional capacity factor shapes in the BPA region and Eastern Montana juxtaposed against the expected BPA demand in 2020. Nightingale commented that the capacity factors are similar in April and May in Montana and the BPA region.

Simmons responded that the biggest difference that he sees is a larger divergence in the winter, with a much higher capacity factor in eastern Montana.

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Tom Kaiserski with the Montana Department of Commerce stated that it's good to see this presentation because it shows that Montana's wind complements the wind in the Columbia Gorge since it "blows at different times of the year."

O'Brien asked if the Council looked at how the winds in the Columbia Gorge and Montana complement each other on a daily basis, such as wind at night versus the day. Simmons stated that they have not, but it would be interesting to determine this. Kaiserski commented that Montana's winter peak is generally during the day. Heutte said the wind in the Northwest is evenly distributed during the day and night, but California winds tend to peak at night.

On slide 17, Simmons showed a hypothetical 18,000 MW wind generation – one scenario with all the capacity in the BPA region, and the second scenario with 50% in region and 50% in eastern Montana. In the second scenario with a mix of in region and eastern Montana wind, the production increased in fall and winter with less production in the summer.

Open Questions

Simmons reviewed a few open questions for discussion on slide 18. One question referred to the diversity of new wind generation in the region and the other focused on the coordination of wind shaping and available transmission in the region.

In regards to how the region coordinates shaping the wind with available transmission, Heutte commented that the topic is a big subject of discussion on the transmission planning side. He said that they are seeing that the "geographic diversity value of not just wind, but all renewables, is underappreciated, and now it's finally getting some significant study." Heutte said it is important to think in terms of "not necessarily peak unit potential, or highest capacity factor, but the highest value to the overall grid." He said he thinks that this is overdue in regards to looking at "the rest of the region and what it can offer," as well as considering "how to maximize the overall benefit, not just the highest capacity factors."

Nightingale, referring to the map of annual average wind speed in the United States on slide 15, said southeast and south-central Oregon has a more extensive area of higher wind capacity and there are several high-voltage lines in the same areas. He said he wonders if there is capacity available in the lines and how the wind in southern Oregon compares to the wind in the Columbia Gorge.

Simmons replied that it would be interesting to look into Nightingale's inquiry.

Heutte said southeast Oregon has good wind speeds, but it is far from transmission. He stated the area has big constraints, such as avian-related issues with birds like the golden eagle. Heutte shared that many other states in the region have similar constraints with birds of prey and protected birds, which may be why there has not been much wind development lately.

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In regards to transmission, Jeff Kugel with PNGC Power stated that getting it to load is an issue. He said that according to PNGC, there would be no long-term transmission available through Bonneville, especially in the summer months, until there are new projects.

Kaiserski commented on the Colstrip line upgrade and said an estimated in-service date is 2017. He said the Montana Department of Commerce hopes the project stays on track, as it will offer a 500-megawatt increase in capacity without any new corridors. Kaiserski shared that his agency thinks the project “will access the diversity benefits in Montana.”

In regards to available transmission, O’Brien asked if the Council has done scenarios to determine how much transmission would be freed up and how much wind would be available if some parts of the Colstrip plant closed.

Simmons replied that this could be a possible scenario studied.

King stated the Council did some similar studies in the Sixth Power Plan and thinks the upgraded information will be available in the Seventh Power Plan.

Heutte said Northwest Energy Coalition is not happy about what is happening with the Montana-to-Washington line and project, explaining that the BPA is having trouble finding the funds and right economic arrangements for it. He talked about the coordination of transmission and power planning, and the different studies completed by various organizations and committees.

Next Steps

Simmons reviewed the next steps for the preliminary wind analysis on slide 19.

Kugel commented that it is important “not (to) assume that the entire transmission capacity that the coal plant was using will now be available for wind because the utility will have to replace that dispatchable energy with similar dispatchable energy, and wind is not dispatchable.”

Heutte stated the “Western Wind and Solar Integration Study” found that spreading geographic diversity is as much an economical consideration as it is an operational consideration, as it ultimately allows a reduction in balancing costs. He said this is important because it allows one to look at the full value of a resource instead of just its maximum productivity.

Nightingale asked how the Council plans to incorporate the study that Heutte mentioned into its analyses.

Black responded that the Council is using three sets of analytics: the Regional Portfolio Model, three geographic nodes for the capacity and adequacy analysis, and flexibility metrics.

Kaiserski said he agrees with Heutte’s comments regarding diversity and studying it.

Floating Offshore Wind Technology

Presenter: Jeff King, J.C. King and Associates

King stated there was an expressed interest in learning more about floating offshore wind technologies in one of the first GRAC meetings. He shared that the Department of Energy recently awarded a grant to build a small prototype in Coos Bay, Oregon, that could come in service as early as 2018.

King reviewed today's discussion on slide 2.

Why the Interest in Floating Wind Plants?

King explained the illustration in slide 3. He said the reasons for the interest in floating wind plants in the Northwest include the ability to develop the offshore resources of the Northwest and the quality of the wind resources available.

King discussed the map on slide 5 which shows both onshore and offshore wind speeds.

Nightingale commented that the quality of wind along the coasts of Oregon and Washington is as good as or better the wind in eastern Montana, especially because they are "closer to load."

King discussed attributes of offshore wind on slide 4 and potential development issues on slide 6.

Offshore Wind Turbine Generator Founding Concepts

King explained the illustration in slide 7, which shows several different offshore wind turbine generator technologies. He said the last three platforms are concepts at this time.

In response to Abadi's question, King said the stabilization components on the platforms probably would consume some power.

Notable Projects

King reviewed the table of notable offshore wind projects (worldwide) on slide 8. He said the list of projects is not exhaustive.

Reported & Projected Capital Costs

King explained the reported and projected capital cost estimates from known projects and reports on the graph on slide 9.

Proposed 7th Plan Treatment

King reviewed the Council's proposed treatment of offshore wind in the Seventh Plan in slide 10.

Nightingale commented that some reports say the cost to deploy a maintenance crew to a platform is a significant expense, making the operations and maintenance too expensive. However, with larger wind turbines now being deployed offshore, that the increased economy of scale might reduce and mitigate the higher maintenance cost expense.

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Heutte stated he agreed about the cost being a hurdle. He talked about some of the reports that he has read and the discussions he has had about offshore wind. Heutte said that in the initial stages of development, the technology can reuse existing transmission. He suggested the Council invite people from Japan and others who manufacture floating wind turbine generators give a presentation.

Nightingale said he wouldn't assume the ocean's wind profile is going to be like the Columbia Gorge's because the gorge has different pressure differentials. He talked about gathering data from sources like the National Oceanic and Atmospheric Administration's data buoys. Nightingale said he wondered if there is a cost or development curve to see if it matches the Council's data. King had not looked at the NOAA data but thought it would be a good information source to tap into.

Hydropower Potential Screening Study

Presenter: Gillian Charles, Northwest Power and Conservation Council

Latest Hydropower Potential Study Creating a Buzz

Charles reviewed slide 2, which focused on the latest Department of Energy's new stream-reach development potential study. She noted that the DOE's study only included the physical characteristics of streams and did not take into consideration feasibility issues arising from environmental impacts, costs or benefits.

O'Brien asked if the study looked at dams already in existence or if it related to flood control for new building developments.

Charles responded that this particular study was for new stream reaches only, but that other studies available focus on existing dams.

Charles explained the maps on slides 3 and 4, which show the national and regional potential identified by the DOE study.

Past Studies, Current Study Objectives and Preliminary Schedule

Charles discussed slides 5, 6 and 7. She said the Council will form a subgroup for its study, and invited the meeting's attendees to participate if they are interested.

O'Brien asked if the study will look at physical potential or how much can realistically be built.

Charles replied that many of the studies only cover physical potential, so the Council will try to determine what is realistically feasible.

Black said the Department of Energy's website has a Non-Powered Dam Resources Assessment and a Stream-Reach Development Resource Assessment, so he assumes the Council will consider both in its studies.

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Black, O'Brien and Heutte discussed the information that the studies cover and the region's protected areas.

Black highlighted that the Council will take protected areas into account for the hydropower study. He said they plan to involve the Council's Fish and Wildlife division in the study.

GRAC Meeting Wrap-Up

Simmons stated the next GRAC meeting, which will take place in about three months or so, will include a follow-up on natural gas peaking technologies and wind, and may cover geothermal energy.

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