Renewable Energy Advisory Council Meeting Notes

Wednesday, May 9, 2018

Attending from the council
Erik Anderson, Pacific Power
JP Batmale, OPUC
Suzanne Leta, SunPower
Michael O'Brien, Renewable Northwest
Adam Schultz, Oregon Department of Energy
Frank Vignola, University of Oregon
Dick Wanderscheid, Bonneville Environmental Foundation
Jason Zappe, PGE

Attending from Energy Trust
Shelly Carlton
Andy Eiden
Becky Engel
Matt Getchell
Jeni Hall
Joe Hernandez
Jed Jorgensen
Dave McClelland
Dave Moldal
Lizzie Rubado
Zack Sipple
Jay Ward
John Volkman
Lily Xu

Others attending
Thomas Farringer, EC Company
Max Green, Renewable Northwest
Ben Haney, City of Salem
Alan Meyer, Energy Trust board
John Reynolds, Energy Trust board
Jue Zhao, City of Salem

Executive Summary:

- Overview of the City of Salem biogas project at Willow Lake Water Pollution Control Facility:
  - Staff requested feedback on this project in advance of a board meeting presentation.
  - Experts from City of Salem provided additional background on the project, costs and timeline.
- Strategic planning update:
  - Questions and discussion about SB 1149 sunset and its impact on renewable incentives beyond 2025.
- Solar peak reduction:
  - Staff presented recent analysis on the impact Energy Trust solar projects have on utility peak.
- Public comment:
  - Questions about Solar + Storage and Energy Trust's involvement.

1. Welcome, introductions, announcements

Jed Jorgensen called the meeting to order at 9:34 a.m. He introduced Joe Hernandez, an Energy Trust staff member, who planned to take photos at the meeting.

The agenda, notes and presentation materials area available on Energy Trust's website at: https://www.energytrust.org/about/public-meetings/renewable-energy-advisory-council-meetings/

Dave McClelland mentioned that there was a small residential solar fire on Monday in Cornelius, which was featured on the local news. The system received incentives from Energy Trust. Firefighters portrayed the fire as extremely rare and said that customers who have solar shouldn't be concerned.

Frank Vignola: What caused the fire?
Dave McClelland: There has not been a formal investigation, but the trade ally's initial assessment was that the fire started at the rapid shutdown device on the roof. The rapid shutdown device is a new code requirement that is meant to protect firefighters in case there is a fire, ironically. We shouldn't speculate further, but more information will be shared with RAC if it comes forward.

2. City of Salem biogas project
Staff presented information about the City of Salem's proposed cogeneration biogas project at its Willow Lake Water Pollution Control Facility (0.87aMW, $3 million proposed incentive). Attending the presentation were Ben Haney, senior project manager at City of Salem, and Jue Zhao, water treatment plant facility manager at Willow Lake.

This project is located in PGE territory and plans to utilize a $3 million PGE renewable development fund grant. The city is also pursuing a $250,000 ODOE renewable energy development grant. The city expects the project to come online in late 2019.

This project is one of several biogas, water treatment, hydro or other projects under review by Energy Trust, resulting from the pipeline-building efforts that occurred in prior years.

Erik Anderson: Is the funding for the competitive solicitation utility-specific?
Jed: Yes. The funding available in each territory is different. We're looking at projects above $150,000.

Alan Meyer: Is the $500,000 in annual operations costs really annual?
Lily Xu: No, that is the total over the life of the project.

JP Batmale: Why are oil changes in maintenance budget not included in the maintenance contract?
Ben Haney: There are different levels of maintenance contracts available, and the city chose a support level for the first five years where the manufacturer will provide almost all maintenance services. Additionally, some maintenance will be performed by staff.

Michael O'Brien: Is the city making any claims about the renewable aspect or clean energy?
Ben: We don't plan to.

JP: What's the estimated time to pay out incentive?
Lily: It's a production-based payout structure, so we will pay out as the milestones are achieved. Staff estimates a two-year payout if the facilities operate as expected.

Michael: What are other alternatives for transfer trip beyond running fiber under the river?

Jed: We asked other municipal facilities about their interconnect processes. None had transfer trip requirements. Instead they use a variety of different built-in safety systems that are designed to shut down when the grid goes down.

Jason Zappe: What is the capacity of these other systems?
Jed: It's a broad range, from a few hundred kW up to 1.7MW.

Michael: Was the goal to create an anti-islanding device or does the utility want to control more than the disconnect?
Ben: It's for wireless communication. PGE is concerned about us putting the full generation potential onto their system, but in reality the cogeneration would never do that. We brainstormed a governor that would shut down the system if we exported the upper limit that exceeds PGE's desire. The specific plan for routing fiber to the substation would be determined during the interconnect application and when PGE does its study. If the costs exceed what we budgeted, the city can cover additional costs.

Jason: PGE evaluated the city's plan at a high level with engineers. Currently it's standard at PGE to require a transfer trip for all rotating machinery over 1MW. During the interconnection study process, PGE will explore all options including transfer trip, radio or other protection schemes.

Michael: I respect the safety aspect. For future projects, if we can avoid fiber as a standard, that is ideal.

JP: How much gas per year per cubic foot will be generated? If the generator goes down, can the digester hold the gas without flaring?
Ben: We produce a lot of gas but the system has very little storage. The system has boilers that run in the event the cogeneration is offline. Any gas that isn't used will be flared but we don't expect that will be much.

JP: How much heat load is there? Is it consistent with electric load?
Ben: We have to heat the primary digesters. There is overlap between heat and electric loads year-round.

JP: Is that calculated in the total cost?
Jed: Yes. They will extend their heat loop to another building that uses gas for heating. We subtracted the gas savings from our biogas tally but passed it onto Energy Trust's Production Efficiency team to see if they can capture the gas efficiency.
Ben: Boilers are basically a backup heating source if the cogeneration system is down.
Jue Zhao: We have two boilers on site that are old but working. They serve as backup to keep the digester warm.

Dick Wanderscheid: I commend the City for doing this type of work for 30 years. How old are the current digesters?
Jue: We installed them in two phases. The first was installed in 1964, the second in 1976.

Dick: Did you look at digesting fats?
Jue: Yes, we did consider it. We analyzed the feasibility through a study conducted through a consulting firm, and we decided it's a no-go at this time.

Dick: Is there back-up fossil fuel if grid goes down?

Jue: No. We looked into it, but this is why we are going to biogas.

Adam Schultz: What are the methane benefits?
Ben: We don't know yet. We flare every day with our existing cogeneration. After this new cogeneration is in place, we expect minimal flare. We have variability in gas production and seasonality, but the new system is built to capture the range. We will not exceed the turn-down capacity. We are minimizing that as much as possible.
Jue: Once the new cogeneration is in, we will have to flare less. We sized the cogeneration system to fit within the range we see today to accommodate high-end and low-end production needs.

Alan: Does the city have money for capital cost? No bond to be issued?
Ben: No. Funded only by utility rate funds.

Frank: How were extreme weather events factored into the plan?
Ben: Extreme weather affects the plants sewage collection system. We see increasing flows during extreme weather events. There are spikes in energy use because of that flow from sewage.
Jue: The liquid stream side during extreme events is impacted more than solid side. We see some impact to the digester but it's modest. We can handle it.

Frank: It's sized to take care of it?
Ben: Yes. We plan for impacts during weather. Solids that get digested are more stable and less affected. It won't impact the gas available. Instead, there is more impact on the flow of electricity.

Erik: Are there federal funds available for wastewater treatment plants for similar projects?
Ben: We investigated them and didn't find any that fit. DEQ offers revolving loan programs and principal relief. These are geared toward small communities in dire need. That doesn't fit Salem.
Jue: We also looked at EPA options, but nothing was applicable.

3. Energy Trust Strategic Planning update

Energy Trust has begun work on its next five-year strategic plan. The strategic planning process will involve input from RAC and CAC. Staff discussed implications of the 2025 sunset of SB1149 for work during the 2020 – 2024 strategic plan period, and requested input from RAC. Staff indicated a need to think through what it means to ramp down programs well before 2025, including contracts, project development, staffing and more. Some projects have long life cycles, hence a need for a longer view.

John Reynolds: Will there still be above-market costs for solar?
JP: That is a good question.

Dick: Would extending the sunset require new legislation?
Jed: Yes. OPUC could direct something else, for example identifying different funding sources to be directed for renewables. The board will have to evaluate these.

Alan: If 1149 is extended it could look different?
Jed: Yes.

JP: Did SB 838 extend the renewable portfolio standard?

Jed: Yes.

Frank: Has Energy Trust talked with utilities on what their perspectives are about renewables?
Jed: I'm unaware of those conversations with utilities regarding SB 1149.

JP: There are other things to think about for strategic planning, not just the SB1149 sunset. Are there other issues you'd like us to think about for strategic planning?
Jed: Yes, there are more than that. This is the only part of the presentation that the renewables team is providing to the board for the kickoff. There are other considerations and around above-market costs that will be discussed.

4. Solar peak reduction

For the 2017 annual report, staff developed a methodology to estimate the effects of solar installations on utility system energy peaks, at the request of OPUC who asked Energy Trust to provide information about how much projects save and generate, and when that occurs. This is the first time Energy Trust has provided information about how projects in general impact peak. Solar is the first renewable to estimate its impact on peak.

To arrive at its estimate, Energy Trust used modeling software to define and organize output generation profiles, or "bins," based on location, tilt and orientation. These profiles can be mapped to an hourly load profile.

Because this is the first time staff has done this analysis, there are more conversations needed with the utilities about the process, the data, and how utilities look at peak, which is defined differently by every utility.

Alan: For Pacific Power, they have installations in Portland and Medford. In your analysis, you looked at individual projects first, but then added all statewide projects together?
Jeni: Correct. It first measured all individual sites, then aggregated that information. The number presented is the average over the peak period. The same project in different locations could have different contributions on peak.

JP: What was installed in each utility territory?
Dave: Last year we had about 25 MW installed, about 15 MW was distributed, 10 MW was larger utility-scale projects in Pacific Power territory. I don't have a split of the distributed projects off hand (2017 solar installations included 9.8 MWdc of PGE projects and 16.2 MWdc of Pacific Power projects).

JP: They gave you hours for peak, and you looked at production of solar in those hours?
Dave: Yes.

Adam: System-wide peak or localized peaks?
Dave: System-wide peak. During the window of peak hours, the solar contribution may range from high to low.

Suzanne Leta: I'm excited about the study. These numbers show a range of 2-6 hours for peak. The range reflects the average over that period?
Dave: Yes.

Frank: Did you check accuracy of the numbers? What is the uncertainty of these?

Dave: We have that question, too. The variability over time and uncertainty of our estimate is unknown. We would need to do more work to analyze this.

Frank: Did you do analysis of system performance monitoring to compare?
Dave: We conducted this analysis over 1-2 months, and it's the first time we've come up with an estimate. There is more follow-on work to compare to actual system production and consider variability. At the annual meeting for Frank's University of Oregon Solar Radiation Monitoring Laboratory, they presented aggregated data characterizing the variability of solar insolation over the year. It would be interesting to use that data to improve our estimates.

Jeni: We built our model from the National Renewable Energy Laboratory's System Advisor Model using TMY3 (typical meteorological year, version 3) data and considered the results of our recent program impact evaluation which showed that solar projects overproduced against our estimates on average.
John: In 2003 we attended the national solar energy conference in Austin. Austin Energy gave money to the convention center to install PV arrays so they were oriented southwest versus south, because they wanted to help with peak there. It's interesting that this long ago, peak was being considered.
Dave: Oregon is well away from a duck curve. California solar will have a bigger impact on our grid than local solar near-term. By shaving off mid-day, it's not creating huge ramping problems for utilities, I don't think.

Alan: If utilities had accurate time of use rates, would we have that problem? California points west because of this.
Erik: California time of use rates are high in the evening, designed to address over-generation of solar. I'm not sure if that's accurate for Oregon. The risk is that California solar will diminish Oregon's solar value as we get more interconnected.
JP: Locational value might help insulate distributed solar from being diminished.

Suzanne: The 5-6 percent peak numbers are only for 2017?
Dave: Yes. This is the estimate we provided to OPUC.

Suzanne: Do you have the ability to look at historic installations too? And do you plan to?
Dave: Yes, the methodology would support that. It is data and time intensive, but could be considered.

Suzanne: I argue it's more worthwhile because there are more projects installed. Could you include non-Energy Trust projects?
Dave: ODOE could be involved in that conversation and decision.

Jason: When you created the model, did it take into account the date those projects came online in 2017?
Jeni: We included projects that were completed any time last year and considered generation going forward. If the goal was to look at locational or more specific, we would take into consideration how much they contributed over a certain time period.

Michael: These are your next steps. What are OPUC next steps?
JP: This could play a role in our work. The resource value of solar dockets (UM 1910, 1911 and 1912) deal with capacity. We are trying to understand the value of capacity.

Suzanne: Who funded this?

Jeni: It was requested by OPUC, and we did the work with in-house resources.
JP: We asked Energy Trust to tell us the estimated capacity contribution, because utility frameworks for IRP were shifting from energy to capacity. Most of the value from Energy Trust is on energy.

In response to staff questions about what else the RAC would like to learn related to capacity, the following comments and questions came forward:

Suzanne: I'd like to see non-Energy Trust projects included.

Frank: In the last 15 years, it's been a steady gain of 5-6 percent for energy efficiency, but we don't know how long this trend will last. For example, how much variation exists year-to-year, how much does it affect forecast, and what are worst-case and best-case scenarios. Because solar data is available, utilities could see if there is a tie-in for availability of solar and loads. It just needs someone to do it.

Adam: Why not use Effective Load Carrying Capability (ELCC) curves?
Michael: We can think about capacity in two ways. One, for both system and ELCC purposes. ELCC helps with planning certain peak hours in the day or year, and what resources are needed to meet unique peaks. Another way to look at it is reduction in peak and a certain number of hours in a year. That's more of an operations way.

Suzanne: If there aren't systems with storage deployed widely, it would be nice to see a theoretical around that.

5. Public Comment

Suzanne Leta discussed Energy Trust's role in Oregon's Solar + Storage market, and encouraged Energy Trust and OPUC to consider future incentives for storage. Staff described Energy Trust's mandate is above-market costs for solar. Storage does not fit into above-market cost. Energy Trust provides some services around storage, but it doesn't consider storage "generation equipment," contrary to how IRS looks at it.

Dave shared some background about Solar + Storage that Energy Trust recently gathered in response to a request by the board to be educated about the topic.

Suzanne discussed several dynamics in Solar + Storage as topics for consideration by Energy Trust, OPUC and RAC:

1. SunPower finds the largest overall growth in Solar + Storage markets are in commercial sectors for demand charge production. While not a trend in Oregon, it is more so in California and Massachusetts because of high rates, high demand charges and available incentives for storage.
2. Instead, there is residential interest in Oregon for Solar + Storage. To date, residential storage has greater deployment across more locations statewide because there is more interest in resilience, having energy backup solutions and storage technology overall. Oregon residential customers are less focused on short payback periods, whereas commercial customers are driven by savings first.
3. Suzanne encouraged Energy Trust to determine where storage could benefit customers in Oregon. She would like to see incentives offered for both storage and expanding existing systems. She also asked OPUC to consider a flexible approach.

Thomas Farringer: I'd like to see more oversight of the Solar + Storage systems being installed. I'd like to help customers take advantage of federal credits.

Alan: Why would we need a higher incentive for storage if customers get financial benefit from having storage in place? Is that a rate issue versus an incentive issue?
Dave: The financial drivers aren't there. Customers are doing this for resilience, similar to buying a backup generator. There are also some early adopters who like the technology.
Adam: There are also equity conversations. It would be nice to think about directing support to public infrastructure, and not just people who have money to do this.
Dave: Yes, that's a consideration for us. Energy Trust has provided project development support for Solar + Storage systems as part of our low- and moderate-income efforts.

Frank: A battery is a component in the system. Energy Trust has limits related to avoided costs. Although PV system costs are coming down, if you add the battery, the cost isn't coming down as much. Could Energy Trust consider an incentive for the overall system cost, including a battery integrated with the utility and some smart meter system?
Dave: We have considered whether it's appropriate to provide an incentive, in discussion with the PUC. To address Alan's question: maybe it should be addressed in rates. That's not our policy or for us to decide.

Suzanne: If Energy Trust wasn't available to offer solar incentives back in 2007, we wouldn't know what the market would have looked like. Energy Trust drives early adoption to make these projects more cost-effective and benefit ratepayers overall. That's different from a rate case.

Alan: Customers save money with or without the battery. Why should Energy Trust pay more incentives for something that helps the customer already? They get different savings or value by shifting usage and storage, but doesn't impact how much they are actually using energy.
JP: We are limited by 1149 and what it says. It would require expanding what it says to incorporate storage, and would have to say that storage is a standard component of a system. It's a question about whether it's complementary or standard.

Suzanne: Does OPUC have flexibility to do that via rule change or order, versus legislation?
JP: We don't have a lot of flexibility. We are just starting pilots with the utilities on the nature of storage and distribution systems. There are other issues beyond Energy Trust incentives related to storage. When you put up use cases of resilience and others, there is a lot of work to be done to unlock value from tariffs. There's value to utilities to have distributed storage. The use case isn't available because there's no tariff for ancillary services.

Jeni: Providing grid benefits doesn't necessarily require communications. There are models where a utility can fully interact with a storage system, and situations where a system is optimized for personal use but also reduces demand on the grid.

Suzanne also answered questions about the SunPower acquisition of SolarWorld.

Members of RAC thanked John Reynolds for his participation on RAC, as this was his last meeting.

6. Adjourn
The meeting adjourned at 11:50 a.m. The next scheduled meeting of the Renewable Energy Advisory Council will be held Wednesday, June 20, 2018.