EnergyTrust of Oregon

RENEWABLE RESOURCE ADVISORY COUNCIL
Notes from meeting on January 13, 2010

Attending from the Council:
Kyle Davis, PacifiCorp
Bill Eddie, BEF
Troy Gagliano, enXco
Theresa Gibney, OPUC
Robert Grott, NW Environmental Business Council
Thor Hinckley, PGE
Suzanne Leta-Liou, Renewable NW Project
Deb Malin, BPA
Robin Straughan, Oregon Department of Energy
Frank Vignola, University of Oregon
Sandra Walden, OSEIA

Attending from the Board:
Dan Davis
John Reynolds

Others attending:
Heather Beusse, enXco
Cory Murman, InSpec Group
Andrew Oberhofer, Intel
Kip Pheil, ODOE (by phone)
Vijay A. Satyal, ODOE
Rebecca Sherman, ODOE

Attending from the Trust:
Doug Boleyn
Kacia Brockman
Sue Fletcher
Erin Johnston
Jed Jorgensen
Betsy Kauffman
David McClelland
Sue Meyer Sample
Elaine Prause
Thad Roth
Peter West
John Volkman

1. Welcome and Introductions

Betsy called the meeting to order at 9:30am. Everyone introduced themselves. The agenda was adopted without changes. The November minutes were adopted without change. There was a request to send minutes as an attachment in the future.

2. RECs and WREGIS

Elaine began with a presentation on Renewable Energy Certificates (RECs) and the Western Renewable Energy Generation Information System (WREGIS). The purpose of the discussion was not to make any decisions but to create a similar base of knowledge of these concepts in preparation for future discussions and decisions related to this topic. Energy Trust has a board policy on RECs (originally known as green tags) which was first developed in 2004 and has since evolved as the market and our understanding of our role has changed through the years. We take title to some RECs for every project that we fund. Our allocation is specified as part of each incentive contract with project owners. The policy also states that we can sell up to 50% of the RECs we own. We have not done so yet.

There are three categories of projects where we see different issues in dealing with REC ownership. RECs from utility scale projects, those large scale wind projects we were able to help fund in coordination with utility RFP processes but no longer do, are passed directly to utilities. Energy Trust took no ownership of these RECs. The second category is qualifying facility and on site generation projects where our share of RECs are all custom to the project, depending on how much we contribute and how that contribution compares to market value for RECs. The last category is for net metered, standard incentive projects solar PV and small wind where the project owner owns the first five years of RECs and we owns the balance.

Theresa asked for more clarification on what the Utility scale category meant. Kyle helped to clarify that for those projects we were able to help fund prior to January 1, 2008 when SB 838 limited our scope to 20MW or less, Master Agreements between Energy Trust and the utilities specified that all RECs go directly to the utilities.

Suzanne asked if these differences in allocations by project type were also a part of the board policy. Elaine answered that they all follow the board policy, just actual implementation differs QF/onsite and net metered allocations are direct interpretations of the board policy.

Theresa asked if the amount of RECs Energy Trust claims for custom projects is proportional to the amount of above market cost we fund or is it more complicated. Elaine answered that it is more complicated and we can walk through that if people want to but Theresa and the group were happy to move ahead, knowing it can be more complex.

Elaine then showed the estimated magnitude of Energy Trust ownership of RECs for 2010 (27,000) and 2015 (154,000) across QF/on site and net metered categories, after assuming Energy Trust helps fund at least 3aMW of new generation and owns a similar percent of RECs as today for custom projects. Looking back to 2007, the first year that RECs can be used to meet RPS standards, Energy Trust could claim ownership to an additional 36,000 RECs.

Energy Trust's REC policy was created prior to the Renewable Portfolio Standard (RPS) for Oregon and WREGIS. WREGIS is the system ODOE approved to issue, monitor, track and transfer RECs toward meeting RPS requirements in the state. WREGIS covers the entire WECC region. The amount of detail needed to describe a REC is significant. Characteristics about the site, the project, the owner and all data needed to determine the vintage of the REC are required.

If a REC isn't registered it can't be bought, sold, transferred or retired, and therefore, Energy Trust does not really have RECs but does have the contractual language to enable their certification. There are benefits to certifying. WREGIS brings many significant benefits to the industry. It provides a rigorous accounting system that's transparent and credible with known standards and criteria and provides the ability to officially retire, transfer, and sell RECs knowing that they are not being double counted. Project owners could also sell or retire RECs for revenue of marketing benefits if registered through WREGIS.

Suzanne asked for clarification, have none of Energy Trust's RECs been certified? Elaine responded that that was true, all our contracts ensure we are able to do so but we have not worked through WREGIS or required project owners do so.

Robert was curious about project owners and if we register would we be registering for the project owners or just for Energy Trust. Elaine mentioned that the full project would need to register, not just the proportion we own and we can't register without their involvement. We don't always have 100 percent of the RECs but would need to make that 100% are registered through WREGIS prior to sorting out allocations within WREGIS.

Kip noted that there are a variety of mechanisms that you can use to deal with accounting obligations. Someone would have to register and build RECs in their account. Then buying and selling/transferring could happen. There are a lot of options.

Kyle added that project generation has to have project registered. There's an initial setup and then you have to regularly update profile on the project. In addition, the project owner has to demonstrate energy was produced through particular meter data which adds a lot more responsibility throughout the project life on the part of the project owner.

This comment was a direct transition to the list of WREGIS requirements outlined in the presentation. The project owner would need to register or designate an agent under an account type of which there are many. Specific equipment is needed for reporting, including a revenue quality meter. If projects are less than 360kW they have the option of self reporting their generation but all other projects are required to contract with a third party Qualified Reporting Entity (QRE) to transmit their regular reporting data to WREGIS. It can be difficult for small projects to participate in WREGIS just like with any large certification process for a small scale operation.

Suzanne asked how does the registration play out for the solar coop. Doug noted that they are registered in WREGIS and Bill provided details on how they have a generation aggregator to register and report. Each site still needs to report their generation but the have an easy to use web interface to facilitate the process.

There are costs related to registering. Fees to WREIGIS include annual registration ($200-$1500) and transactions costs on a per REC basis. In addition, for projects above the self reporting limit of 360kW, there are costs to the QRE. $297 for set up and then a monthly fee of $59 if the utility were to provide this service. There are costs for equipment for metering and administrative costs on the part of the Energy Trust, project owner and utility which are difficult to estimate.

An example of certification costs for a QF project ranged from 12-26 cents/REC. In comparison, a small scale PV project would pay $200/yr plus costs of reporting, highlighting the need for other options such as a generation aggregator role.

There are additional complexities we deal with. Each of the custom projects is different in amount of RECs we own and timing of ownership. We see this flexibility as important for us to retain for ratepayers and project owner needs. We work with a variety of project owners, some only want to retire the RECs and claim all the environmental benefits, others want to sell the RECs for an additional revenue stream and for projects where we take all the RECs, is it realistic for us to expect project owners to be motivated to work with WREGIS on an ongoing basis to report generation?

In thinking about Energy Trust's role with WREGIS and REC certification there are important issues to consider.

- What could our role look like? What's the best least cost option?
- Who would pay the costs of registering, reporting, administration and equipment?
- Do the benefits outweigh the costs? From whose perspective? For which project types?
- Are there options to mitigate the costs?
- How does timing impact benefits and costs?

Bill recommends adding language in the incentive agreements that designate Energy Trust as the owner, that is what BEF is doing. There is a fair bit of paperwork but it is doable, depending on resources you have to devote to the work.

Kyle suggests referring to Appendix F of the WREIG regulations as a way to handle rooftop solar by aggregating up to 250 kW of systems. This would give Energy Trust the agent role, and WREGIS would then issue RECs.

Suzanne commented that cost sharing seems reasonable. If Energy Trust is sharing RECs with project owners, then Energy Trust shouldn't need to shoulder the costs of registration.

Theresa added that if Energy Trust thinks of their contract with generators as a contract to exchange things of value, generation doesn't have anything of value if RECs haven't been registered. You could then argue that the cost of the REC is a part of the project cost and would then consider it in the above market cost evaluation. You could then calculate certification as a one time expense instead of an ongoing exposure.

Kip thought it would be nearly impossible to guess a value for the RECs when calculating above market costs. Having the utility register the projects is probably the least cost route. Another possibility is for the Trust to sell a portion of the RECs to cover the administrative costs of doing so. If you were to sell 10 percent, 3500 RECs/yr at $10/REC have $35,000 to cover costs. Then pay to get the older vintage, 2007-2009 RECs into WREGIS.

Frank thought that certifying the RECS and incurring administrative overhead makes sense if you're going to sell but if you're sitting on them anyway, do you even need to certify?

Robert supported Energy Trust in confronting the topic. There could be false impressions that the customer has some value in owning RECs when in fact it takes effort to certify them for use. For small net metered projects, it makes sense to enable aggregation or give them away, but for larger projects, go all the way and certify them

Bill mentioned that aggregation still has a data issue. Solar Oregon has a web tool for homeowners to log data online but they still need to log in and provide the information. He also suggested looking at the REC policy limitation at selling 50% requirement. If we decide to sell, it may be reasonable to revisit that percentage limit and match up the policy with a REC management strategy.

PacifiCorp and PGE are not selling their RECs, they are banking them.

3. Updates on recommended changes to the BETC and impact on Energy Trust incentives and procedures

Jed began with a presentation on recent changes and proposed changes to the Oregon Business Energy Tax Credit (BETC) and potential implications or impacts for Energy Trust. Jed qualified his presentation with the caveat that it is based on Energy Trust's current best understanding of the situation and that he may be mistaken or under informed on some points. Representatives from ODOE should chime in if he misspeaks.

All changes fall under one real goal: to reduce the fiscal impact of the BETC program. There are three areas of change: 1) New temporary rules, 2) A new rule making on the pass-through program, and 3) ODOE's Recommendations to the Governor.

New Temporary Rules. This change stems from veto of HB2472 during the last legislative session. This bill would have changed the maximum BETC available to big wind projects. In the Governor's veto he asked ODOE to tighten the administrative rules for the program and they have done so. ODOE staff also expect the legislature to take further action in this regard.

The new temporary rules are significantly longer than the old rules, but they only really impact Energy Trust in two ways:

1. The old rules allowed a final BETC to be up to 110% of the amount that was pre-certified. This was generous and helped projects that experienced cost overruns. This will no longer be the case. A project will get no more than 100% of their pre-cert. The final amount could go down is a project comes in under budget.

2. The second change targets projects being split up to claim multiple BETCs. The new rules create a series of tests to determine if a facility is "separate and distinct." The rules are written broadly. It is possible that they could result in a project developer being limited to the maximum of $20 million in BETC eligible costs in a given year regardless of the number of projects being developed. Jed noted that within the hydro market it would be very difficult for a developers working on multiple projects on the same irrigation system to claim they are separate and distinct, regardless of configuration or separate interconnections.

Vijay noted that the thought within ODOE about this change is very fluid at this point.

Suzanne commented that a lot of her members have asked about this "separate and distinct" provision. She talked with Andrea Simmons from ODOE. Andrea made it clear to her that if a developer has multiple projects in the pre-cert stage they can request that ODOE review their application to see if they are in compliance with these rules. ODOE will provide information back. It's hard for a project developer to know if they are separate and distinct without confirmation from ODOE.

New pass-through rule making. HB2068 was passed in the 2009 legislative session and asked ODOE to establish a new pass-through formula tied to "inflation and market real rate of return." The rule making occurred in the last two months and the new pass-through rule was released on Monday of this week.

The new formula is based on the t-note and inflation. It increases pass-through rates but the new rates are different for public versus for profit institutions. Public entities will get a 36.8% pass-through. For profit entities will get a 41.18% pass-through. The new rates are effective starting January 1st 2010. Pre-certifications prior to that date will get the old rates. The new rates will be revisited quarterly.

For for-profit pass-throughs the new rate changes the ratio between risk and rate of return. The risk in buying a pass through is related to having the taxable income to use the credit in the out years. The new rate of return is much closer to that of a treasury note – a risk free investment. This may not make it a worthwhile investment. We may see changes in project deal structures so that the credit can essentially be passed-through internally. New, more complicated deal structures could increase above market costs for projects.

For public entities the rate is fairly close to the current rate. It may be slightly more challenging to find a pass-through partner as the rate of return for the partner is dropping, but Energy Trust does not anticipate a significant impact for this market segment.

ODOE's Recommendations to the Governor. In late August the Governor asked ODOE to study a wide variety of things related to the BETC program. ODOE completed their study and released their recommendations at the end of November. There are six areas in the recommendation that may have an impact on Energy Trust.

1. Tighter application requirements. ODOE will require more detailed information for preliminary certification. This favors well thought-out, feasible projects. It would have an unknown impact on Energy Trust.

Suzanne noted that one potential impact is that Energy Trust might get less of a rush of requests because there would be fewer applications for tax credit money.

2. ODOE suggests that public purpose funds should be deducted from a project's eligible costs. This suggestion was made and rejected during the last legislative session. Energy Trust is concerned about this recommendation because it may set up a circular math situation with regard to the calculation of Energy Trust incentives. If Energy Trusts incentive is deducted from the BETC, any increase in an Energy Trust incentive to compensate will be cancelled out by a deduction in the BETC.

In conversation with ODOE staff it seems that the goal may be to ensure that no project receives more than 100% of its costs through incentives or tax credits. This position does not represent a change from existing policy. Energy Trust would like further clarity as to whether the 100% would apply to a project's total costs or to its BETC eligible costs. If the change were applied on an eligible cost basis, projects with poor financial performance could potentially see their BETC lowered by the amount of Energy Trust's incentive.

Sandra noted the eligible cost issue affects third party solar as ODOE does not consider third-party costs as eligible.

Suzanne asked for ODOE to provide more clarity on the issue.

Heather asked if ODOE looks at incentives before or after tax.

Vijay responded that he thinks it is before tax. He said he could get additional information to verify that.

3. Programmatic Cost Cap. ODOE suggests that the BETC program should be capped based on a percentage of the operating revenues of Oregon's energy suppliers. ODOE suggests a 1-4% range, which would yield a biennial program cap of $73 – 292 million.

This would limit the size of the BETC program and could result in less money being available for renewable projects, meaning that Above Market Costs could increase.

4. Alternative Incentive Cap for Wind Projects. ODOE believes that wind projects are competitive with traditional generation sources at this point and suggests the BETC for these projects needs to reflect that fact and slowly be eliminated. ODOE's recommendation is to change the BETC for wind projects above $100,000 in project costs to a 5% BETC with a $200 million eligible cost cap. The BETC would be taken in 1% increments over 5 years. However, the 5% credit would also be reduced 1% per year until it is eliminated.

This change would have significant impacts for Energy Trust's involvement in the wind market for projects between 10kW to 20MW in capacity. Those projects, which Energy Trust does not feel are cost competitive with traditional generation sources, would see a large financial impact and an associated increase in Above Market Costs.

5. ODOE suggests that projects should be prioritized based on job creation, generation, and market readiness. The impact to Energy Trust is unknown as we cannot forecast which projects would meet ODOE's priority criteria.

6. ODOE recommends that some suggestions should be retroactive. They suggest applying the Program Cap and Alternative Incentive Model to all pre-cert projects back to at least July 1, 2009. In addition, they recommend accountability measures should be retroactive to all projects without final certifications.

Erin noted that some small wind projects would be impacted by the retroactive changes.

Robert noted that the presentation understates the issue. Major changes in the BETC would require that all financial dealings be reconsidered since Energy Trust doesn't have the funds to replace the BETC.

Betsy noted that a few things are not fleshed out yet in ODOE's recommendations. They mention wanting to explore a competitive process for applications. Together some of these things could have an impact on the predictability of applications. If it is hard to know what a project needs, it makes our job a little more difficult.

Vijay noted that ODOE is working on a larger study of the impacts and results of the BETC on the projects it has funded. That study is in the planning phase right now and will be completed in October. It will include looking at other incentives that are on the table for projects. He noted that these were temporary recommendations that were made and that this legislation could change. ODOE wants to understand market maturity better. The overarching goal is to study and better plan for use of funds.

Kyle asked when this will be sorted out.

Vijay responded that by March we will have more clarify on the proposed rule changes. The impact to ODOE and Energy Trust on joint projects will clear up through the summer.

Suzanne noted that her organization has been working on BETC issues for the past year. They have reviewed the recommendations and provided comments. They could provide their response to the report if anyone is interested. They are meeting with the legislature and the Governor to get a better sense of where the legislation will go. The Revenue Committee meets this week. We'll know more in a week or two. Things could change in February, but ideally the Governor and the leadership will have one package they agree on that moves quickly through in February.

Robert noted that the new rules resulting from any legislation will be promulgated in March and April and there will be a public meeting some time in March.

10:20 Break

3. Wave Projects – discussion about issues and roles

Betsy made a presentation on wave power generically, although some specific projects were mentioned. She said the big question for the RAC members is how comfortable they are with the risks associated with wave projects at this point. She started by recapping information presented at the November meeting. She said the industry is small at this point with less than one megawatt of generating capacity in the water. Oregon communities, fishing groups, and environmental interests are engaged, and baseline environmental studies are underway. Betsy reviewed the three example technologies discussed at the last meeting to show the variety of technologies being developed. They included: an onshore system where wave energy compresses air that drives a conventional hydro turbine and two floating systems. Continuing the recap of the November presentation, Betsy said that she had presented three options for ETO involvement. The first is to continue to wait which is what we have been doing. The next level is to support OWET, the third is to examine idea of providing financial support to a project. Betsy closed her introductory remarks by recapping the Ocean Power Technologies project's costs and timeline.

The next part of the presentation was a discussion of issues.

Betsy said that John Reynolds had requested a cost comparison at the last meeting. She presented a graph that showed dollars of upfront project cost per annual megawatt-hour produced for various technologies. Biopower is at the low end at $508, wind a little higher at $780, and our most expensive conventional technology, solar, at the high end at $6,154. Phase 1 of the OPT project came in at $43,488 and phase 2 at $9,785. Betsy pointed out that Phase 1 is 87 times as expensive as biopower. Phase 2 is 50% more expensive than solar, our most expensive technology.

Deb Malin asked what capacity factor was assumed for the wave projects. Betsy answered that she used 35% after consulting with Justin Klure, who said that was a conservative estimate.

Betsy then reviewed how Energy Trust normally operates. We fund projects, we look at above-market cost, we take title to tags, we and ratepayers get direct benefits, and projects use replicable technologies. Betsy said wave doesn't fit the standard model. For example, the simple payback on phase 1 of the OPT project is about 750 years which makes it difficult to determine above market costs. In the long term, we expect PGE and Pacific Power to be involved in wave but not right now.

Betsy explained that we do have a demonstration project policy. It's possible that wave projects could fit into that policy, but it has criteria: projects must lead to projects in PGE/PAC territory, must have a plan for what will be demonstrated and to whom, must deliver benefits (RECs) to PGE or PAC, and the above-market cost methodology still applies. Pre-commercial projects need to be deployed in realistic conditions and have to be important for building the market.

Betsy said that because wave projects don't fit our models well, we would need a compelling reason to provide funding. She asked for the group's thoughts about a series of questions:

1. Are we essential? What value do we bring?
2. What direct benefit do we (and ratepayers) receive?
3. What role will these early projects play in developing the market as a whole?
4. What precedent are we setting?
5. Can we live with all outcomes?
6. Do the economics of our incentive make sense?

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Betsy said that 4 and 5 are very important questions. Regarding 4, if we decide that we are going to make an exception then it might have implications for other technologies. Question 5 is about the risky nature of these projects. Buoys could sink for example. Can we live with the possible article about a dead whale? What if we fund an early project and the technology turns out to be the least successful in the long term.

Deb Malin asked what OWET (Oregon Wave Energy Trust) spends its money on. Betsy answered baseline research and stakeholder engagement, industry support, and regulatory work – efforts to seed the field for these projects.

Frank Vignola commented that this seems like more research to develop engineering data than demonstration. He said the first ones are going to be tests and it is more appropriate for them to receive funding from DOE or NREL. He said it's unclear if this is going to be a reliable source of electricity and added that ETO does not fund research. It might be more appropriate for us to provide funding for OWET.

Betsy asked both Kyle David from Pacific Power and Thor Hinckley from Portland General Electric how the utilities are viewing this.

Kyle said PAC has sponsored forums with OSU because the utility wants to know the environmental impacts. He said Pac has been approached to do demonstration/research projects and has said no so far. He sees this as a shaking out period. He said it is conceivable that the utility could participate in a multi-utility research or demonstration project to get energy/performance data. Once there are results, the utility could look into funding projects that sell power to PAC. He said this is similar to wind in late 90s. The projects being talked about right now would connect with and sell to muni's and coops. Kyle said that if Oregon wants to support R & D, it should happen at state level rather than having the customers of single utilities support it.

Betsy asked Kyle if he had a sense of when he expects wave projects to get to the point of selling to the two IOUs. He said PAC likes diversification, but wave is 4th on the list. He said PAC will do more on the others before getting to wave, adding the utility doesn't typically do R & D.

Thor Hinkley said that PGE is contributing to R and D through the work OSU is doing. He said PGE is just as conservative as PAC on this issue and added that his service territory does not have any exposure on the coast. Should an opportunity for PGE to be an offtaker come along, PGE would be interested in looking into it. PGE is interested in technologies that are further down the commercial development curve.

Neither utility said it is financially supporting OWET.

Robert Grott said his big concern about wave is that we don't have enough money to make a difference.

Betsy replied to this saying that others say yes and no on that point. She said our money is symbolically important. One argument she has heard is that wave will happen, the question is where. Do we want it to happen in Oregon?

Robert said that is the reason state as an entity should take the lead on supporting it.

Peter said we leverage USDA funds as part of our programs. We just provided funding for 40 USDA applications at a cost to us of a fraction of the amount that grantees received. That effort took years to get going.

Robert said Energy Trust wasn't the first to be involved with USDA.

Frank said that Energy Trust has criteria and others might use the criteria we establish. He asked if we want to break our criteria?

Kyle drew an analogy to geothermal. He said we see a lot of potential in Oregon, but there is a lack of resources there. There is high risk for $2-3 million hole, but once you find a good location, you get base load, cost effective resources. He wondered if we funded what amounts to wave research, could we be asked to help explore Oregon for geothermal sites. He said it's a more advanced technology, but carries development risk.

Sandra Walden commented that Oregon is blessed with a variety of renewable energy resources. She said that Energy Trust has an ability to legitimize technologies. She suggested that maybe Energy Trust should reconsider our role of coordination with the state. She said we have the resources to help and to assist in technology discussions. Suzanne Leta-Liou from Renewable Northwest Project said her organization monitors technology development. She said she would like to see expansion of resource types, but the challenges that have been mentioned regarding Energy Trust's involvement are significant, specifically the research focus, the fact that Energy Trust customers are not served, and the concerns about precedent. She suggested that supporting OWET might be an option, but she she said OWET's role is similar to her organization's role. She doesn't expect ETO to fund her organization and wonders what value ETO can provide to OWET.

Frank said it might be better for Energy Trust to funnel some support through OSU. If there is a push for research from the state, perhaps ETO should be involved in that.

Betsy said there is precedent for support of trade groups such as, OSEIA and OSWEA, but there is a question about whether OWET falls into the same category.

John Reynolds said his interest in wave is the fact that Oregon's wave resource is so good. Despite environmental concerns, we have a big resource available. He added that it peaks in the winter and serves as a nice complement to solar power. Because Oregon may be the best state for wave, he wants to keep the issue in front of the RAC from time to time.

Heather from Enxco said her company would like to see wave here. When Energy Trust got into wind, it was 15 years into development. She said her company has a position in a wave company, but they don't give it much time at this point. Because it's considered high risk, they need big returns and are looking to prove out the technology in places where the revenues (i.e. energy prices) and therefore, the returns are high. They're waiting to see the technology developed in other countries before getting involved.

Dan Davis asked if it might be valuable to look at what EPRI and NREL have done in the wave space.

4. Update on Solar Budget

Kacia summarized the outcome of the solar electric budget shortfall that was discussed at the last RAC meeting. In November we received a rush of incentive applications requesting more money than was available in the 2009 incentive budget. At the time the RAC supported staff's proposal to use money that had been set aside for potential large scale solar projects to fund as many of those applications as possible. Responding to the RAC's concern that many of the applications wouldn't lead to "real" projects, staff reviewed the attrition rate within the program to date. It was learned that just 1% of residential incentives and 25% of commercial incentives reserved end up not being spent. Applying the same attrition rate to the new project applications allowed more projects to be approved based on the expected actual budget impact.

The large-scale solar RFP funds couldn't be tapped until after those funds were added to the 2010 solar electric budget, which was approved in December. So staff approved projects from the November rush on a first come, first served basis until the 2009 budget plus 75 percent of the original 2010 budget was committed. This allowed all of the PGE and most of the Pacific Power projects to be funded at the higher incentive rate. 55 Pacific Power projects received in the last three days of the rush were told they were not eligible at the higher rate. Many of those projects have decided to proceed at the lower incentive rate. The new, lower rates went into effect November 9, 2009.

Kacia predicted that the full $2.3 million of Pacific Power RFP funds and just a portion of the $5 million of PGE RFP funds will be needed to pay for the projects accepted during the rush. With these RFP funds, the budget available for *new* projects in 2010 will be roughly equal to the 2009 budget. A decision about whether any PGE funds can be directed toward a large scale RFP will be made after the effect of potential BETC changes and feed-in tariff decisions are known in the coming months.

John Reynolds asked how many Pacific Power projects we accepted, compared to the 55 projects rejected. Kacia estimated about half of the Pacific Power applications received during the rush were accepted. She also responded that most of the rejected applications were for commercial projects, particularly some larger third party-owned commercial.

Kyle asked Energy Trust to communicate with Pacific Power's net metering staff about the expected rush of applications, because Pacific Power has not yet received them. Kacia agreed.

A member of the public asked if the 2010 budget will support the current volume of applications under the new, lower incentive rates. Kacia responded that the program is still receiving a steady stream of new applications, mostly residential, and is looking into whether the current incentive rates will be sustainable.

John Reynolds asked for a summary of the projects accepted and rejected, residential and commercial, etc. Kacia noted that a summary of 2009, including the project activity during the November rush, will be provided to the solar trade allies after Energy Trust closes the books for 2009, and will be shared with the RAC.

5. Public Comment

There were no public comments.

6. Meeting adjournment

Betsy thanked all RAC members for their participation and adjourned the meeting at 11:45am.