Agenda

Renewable Energy Advisory Council
Wednesday, October 25, 2017: 9:30 a.m. – Noon
http://www.energytrust.org/about/public-meetings/renewable-energy-advisory-council-meetings/

Energy Trust conference room Kilowatt
421 SW Oak St., Suite 300
Portland, Oregon 97204

9:30 **Welcome, introductions, announcements** **Information**

9:35 **Opal Springs hydro project** **Information**

- Staff will present an update to the Opal Springs hydro project (0.12 aMW, $450,000 incentive).

9:50 **Three Sisters Irrigation District Watson hydro project** **Information**

- Staff will present the Watson hydro project (0.09 aMW, $360,000 incentive).

10:05 **Three Sisters Irrigation District McKenzie Hydro** **Information and feedback**

- Staff will present the McKenzie hydro project (0.11 aMW) proposed for a $640,000 incentive).

10:35 **Break**

10:45 **Budget** **Information and feedback**

- Staff will present the draft 2018 annual budget, building from the draft action plan presentation in September. The public comment period on the draft budget is from November 1 – 17, 2017.

11:45 **Public comment**

12:00 **Adjourn**

You can view this agenda and meeting notes at: http://www.energytrust.org/about/public-meetings/renewable-energy-advisory-council-meetings/. If you have comments on meeting notes, please alert Jed Jorgensen at jed.jorgensen@energytrust.org.

Upcoming RAC meetings:
Friday, November 17

Renewable Energy Advisory Council Meeting Notes

September 15, 2017

Attending from the council:
JP Batmale, Oregon Public Utility Commission (by phone)
Michael O'Brien, Renewable Northwest
Adam Schultz, Oregon Department of Energy
Frank Vignola, University of Oregon
Dick Wanderscheid, Bonneville Environmental Foundation
Erik Anderson, Pacific Power
Les Perkins, Farmers Irrigation District
Suzanne Leta-Liou, SunPower

Attending from Energy Trust:
Amber Cole
Matt Getchell
Jeni Hall
Andy Hua
Jed Jorgensen
Corey Kehoe
Judge Kemp
Steve Lacey
Dave McClelland
Dave Moldal
Connor Morrow
Lizzie Rubado
Zach Sippel

Others attending:
Brandon Adams, North Coast Electric
Heather Beusse Eberhardt, Energy Trust Board of Directors
Megan Craig, Oregon Solar Energy Industries Association/Solar Oregon
Alan Meyer, Energy Trust Board of Directors
John Miller, OSEIA
Richa Pondyal, 3 Degrees
John Reynolds, Energy Trust Board of Directors
Jason Zappe, Portland General Electric

1. Welcome, Introductions and Updates

Jed Jorgensen convened the meeting at 9:30 a.m. The agenda, notes and presentation materials are available on Energy Trust's website at: https://www.energytrust.org/about/public-meetings/renewable-energy-advisory-council-meetings/. Jed will preside for Betsy Kauffman going forward.

2. Low-to-Moderate Income Solar Update

Lizzie Rubado, renewable energy program strategies manager, is the lead on the sector's effort to serve low-to-moderate income residents that began last fall. With funding from a U.S. Department of Energy grant, Energy Trust and the Oregon Department of Energy started a three-year effort to investigate barriers and solutions to increase access to solar energy for lower- and middle-income customers in Oregon. Oregon is one of six states working on this issue under this grant, providing an opportunity to learn with and from other states as we perform this work. This work is also supported with research from Lawrence Berkley National Lab and the National Renewable Energy Lab.

Energy Trust is working to to establish a strong stakeholder engagement process to inform this work and ensure that we heard from low- and moderate income communities about their needs, experiences and solutions. Zach Sippel, renewable energy project coordinator, created a non-Energy Trust website for information about this work at www.imisolaroregon.wordpress.com.

The stakeholder engagement process kicked off in January 2017 with a road show, a series of listening and needs gathering workshops with community organizations and residents. Joining

Energy Trust were representatives from the Oregon Department of Energy, Sustainable Northwest, Spark Northwest and the Oregon Public Utilities Commission. Representatives traveled to Roseburg, Redmond and Hood River to provide information to community groups about the current status of community solar rule-making, efforts that are underway in other states, and to gather ideas from the public prior to developing a strategy. Another listening session was held in Portland at the Immigration and Refugee Community Organization, with 143 individuals from agencies, affordable housing developers, clean energy and environmental groups, and residents in attendance.

A stakeholder process was built on these outreach efforts. From there, a work group was established to look at the state and where needs can best be served with solar. There are 20 member organizations involved. Of these, about one-half are community based, providing direct services to low- and moderate-income customers. The work group is investing efforts and resources to support the participation of groups that may often be underrepresented. With the grant funds, the work group has been able to compensate some of the community organizations for their time and expertise. The work group is incorporating Energy Trust’s Diversity, Equity and Inclusion Initiative efforts in planning and listening sessions and going forward.

The objectives of the work group are to develop an inclusive process to address solutions for low- and moderate-income communities. This includes building relationships with community based organizations; increasing understanding about topics related to low- and moderate-income solar, including affordable housing, low-income energy programs, solar project finance and resiliency; and informing the development of a LMI solar strategy for Oregon

For the past three months, the group has worked through a variety of different topics in depth, including workforce development and diversity, community engagement, opportunities in affordable multifamily housing, resiliency and solar plus storage, and integration and co-benefits with existing energy assistance programs. At a recent meeting, the work group explored the risks and opportunities associated with supporting low-income solar using weatherization or energy assistance funds. There are complex arguments to be made for and against this approach, and the conversation with the work group was insightful. The work group will talk about financial models in October.

Work group discussions will drive the development of a strategy with prioritized recommendations, which is a deliverable under the grant. A first draft of this strategy is expected in December and will be followed by gathering stakeholder feedback.

While Energy Trust is facilitating this work, the strategy will not be an Energy Trust low- and moderate-income strategy. However, we hope to see opportunities where Energy Trust can perform meaningful work down the line. This strategy will not include advocating for policy changes, but it will be examined for policy barriers in a research and reference capacity. After strategy development, an implementation plan should come in mid-2018, and then work will begin to spread the identified initiatives throughout state.

Dick Wanderscheid: This is a vexing problem. Bonneville Environmental Foundation has been working in this space for two years and has received grants to test models. The reality is that this problem is hard to solve. Other states have attempted, some more successful than others. However, the beauty of the process is the people at the table. There are people engaged with energy issues that haven’t been before, and it all started with community solar rule making. Therefore, I think the results are going to point to some areas we need to fix. With electric rates in the Pacific Northwest, or at least in Oregon, it is difficult to make a business case until we know the value of solar and what is going to happen with community solar in both program implementation and the low-income administrator. However, we should be well poised when final a program comes out. It is frustrating for us because we have been working in this space for a while, know the barriers and are trying to bring people up to speed on this complex process. I commend Energy Trust for bringing this group together and being committed to coming up with a product to help implement these ideas.

Alan Meyer: Is the group open to the possibility that this just isn't meant to be? It seems to be like Mercedes trying to figure out how to sell cars to low-income folks, when those folks are focused on food and basic needs rather than buying a high-end luxury car.
Lizzie Rubado: No, I don't think this group believes that this is not meant to be. I think there is a commitment on the part of the work group members to figure out how to make it work. This group, and this effort, is looking at solar solutions across the board—not just rooftop solar for single-family homes. When you look at the greater landscape of opportunities to serve those in lower-income communities with solar, you can see that there are many opportunities, including community solar, affordable housing, organizations that provide services to lower-income people, and even the workforce and education piece. I believe, and I think most work group members also believe, that there are solutions that can work.

Les Perkins: I have been on the Housing Authority board in the five county region for development of low-income housing, and this has been a struggle all along to figure out how to incorporate solar. Affordable housing projects have failed in the past or experienced significant issues because of cheap construction and housing that's not on par with what's in an aggressive marketplace. Our board sees the need to invest in these projects for the next 50 years, and solar should be a part of that.
Alan Meyer: But the other obvious answer is the groups that are using that kind of time horizon are the utilities. If they couldn't do it, that is the other extreme.

Dick Wanderscheid: The community solar rules are mandating low-income carve out, and we don't know how the rules are going to work. We have identified two or three models that to implement, so it is doable. It is encouraging that there is movement to find a way to help comply with community solar rules that say every project has to have 5 percent of low- and moderate-income and the overall program has to have 10 percent. That is something we have to figure out. Other states have mandated that utilities get involved. Colorado came up with a mandate where utilities can be involved, but we are a long way away from that right now.

Michael O'Brien: My fears have been allayed after Lizzie's presentation. It sounds like you are really trying to listen to what people need. In past conversations, it sounded like we were telling people what they should want rather than us listening to what they need. In the conversations around the use of money going to customers who couldn't pay their bills and the possibility that some of those funds could go to low-income solar, can you characterize how funding has been justified?
Lizzie Rubado: There are two primary categories of low-income energy assistance at the federal level that trickle down to the state level. First, one pot of money is dedicated to weatherization for low-income energy solutions, and some of the Public Purpose Charge goes to supplement that. Second, the majority of funding goes to energy assistance for emergency situations, where low-income customers have had or are at risk of having power shut off or losing heat during the winter.

In the conversation about the appropriateness of integrating solar into these programs, the greatest sensitivity is about adding solar to the emergency energy assistance programs. Emergency assistance funding provides a vital service when people are in dire need, and there is greater demand is greater than the budget—yet are very cheap to administer. Advocates for making solar part of that program see an opportunity to provide assistance with a longer shelf life. Instead of a one-time payment to help with arrears or emergencies, the funds could assist with a community solar project that would lower bills for years. Many customers have to use assistance dollars year after year, and many of them assistance indefinitely because they are seniors, have a disability or are in a permanent low-income situation.

Lizzie will provide periodic updates on the work and draft strategy.

3. Draft 2018-2019 Action Plans

Jed presented an early draft of the 2018-2019 Budget Action Plans with numbers to follow next month. He outlined the budget schedule and introduced Director of Communications and Customer Service Amber Cole to review the process. The budget cycle began in July and included forecasting work with the utilities. Program action plans are in the draft stage and will be circulated to stakeholders for feedback. The public comment period will begin on November 1 with a deadline of November 17. The 2018 budget process will conclude with a vote at the December 15 meeting of Energy Trust's Board of Directors. Amber asked the committee to provide input to Energy Trust staff contacts or to Energy Programs Director Peter West by November 17.

Amber reviewed the focus areas and associated themes for all Energy Trust programs. The budget themes support Energy Trust's core mission to achieve energy efficiency and renewable goals. Budget themes are to improve planning and budgeting processes, prepare for future changes and opportunities, expand customer participation, and apply a diversity equity and inclusion lens to activities.

Jed summarized the budget review committee's outreach to Renewable Energy Advisory Council, Conservation Advisory Council and the board. One thing that surfaced from these interviews was that people wanted a refresher on their role in the budget process. One of the overarching goals for the budget process is to maintain transparency as an organization. Energy Trust looks to advisory council members for feedback on whether we are moving in the right direction.

Jed provided an overview on the Other Renewables program and said its action plan is about 95 percent the same as the past three years. Solar is in a period of rapid change.

Suzanne Leta-Liou: Can you remind us the total renewable energy budget versus a portion of the budget for Other Renewables and the portion of the budget for Solar?

Jed: Numbers will be covered next month. The budget totals approximately $14 million dollars in new revenue. The split over time has tended to be 60/40 Solar. This year will likely be closer to a 50/50 split. Because the Other Renewables program has been very successful in deploying funds, there is less money rolling over into the Solar program.

In 2018, the Other Renewables program plans to continue project development assistance and installation incentive support, continue to focus on biogas and hydropower opportunities while remaining open to other technologies, and continue project optimization efforts with operational facilities.

In 2018, there will be fewer renewable energy incentives, grants and tax credits in the market. We also expect continued decreases in avoided cost prices available for qualifying facilities and continued demand for biogas for vehicle fueling and pipeline injection due to new environmental commodity markets

All projects will be impacted by the reduction in grants. Net-metered projects are not impacted by avoided cost changes but Qualifying Facility projects will have higher above-market costs. Energy Trust will have to provide more funding into project installations in the absence of other grants.

Michael O'Brien: What are the new emerging markets?
Dave Moldal: Renewable Identification Numbers is driven by California's Low Carbon Fuel Standard Program and Oregon's Clean Fuels Program. These are all non-energy attributes that can be monetized at a much higher value than the actual commodities.

Jed Jorgensen: We are looking at expanding participation by continuing to offer competitive opportunities for projects to apply for installation incentives focused on irrigation hydropower and net-metered biogas installations. We are seeing new districts added into irrigation modernization. We are performing additional outreach to water resource recovery facilities, and there is a set of smaller facilities that are looking at net-zero energy use through solar and/or biogas opportunities.

In a first phase of irrigation modernization work, Energy Trust is performing an assessment of benefits an irrigation district can uncover by piping a canal and turning it into a pressurized pipe. That assessment provides a system improvement plan that lays out opportunities. The first step in this planning process doesn't get us to the design of the hydropower project, but to where it makes sense to have a project. The second stage is to determine how to plans to the design process and implementation.

Energy Trust is deepening our relationships with water resource recovery facilities to offer both Other Renewables opportunities and energy-efficiency upgrades.

Jed reported on the project optimization and evaluation work that Energy Trust has performed over the last year. At the end of 2016, Dave Moldal ran a request for proposals to evaluate some facilities that received Energy Trust incentives. We looked at three projects to identify areas with room for improvement.

Energy Trust will continue to manage Renewable Energy Certificate (REC) delivery and work to improve reporting capabilities to reduce time spent responding to data requests.

Michael O'Brien: Is there some problem with the work on REC delivery, or is this administrative work you're performing?
Jed Jorgensen: With custom projects, there are a set of projects that were installed prior to the REC market and we have been working with utilities to see if we need to go back and have those projects registered in the Western Renewable Energy Generation Information System (WREGIS). The answer for some projects was affirmative and not for others. We already have a set of facilities to ensure the REC registration transactions.

Dave McClelland thanked the Renewable Energy Advisory Council for its feedback during the August meeting about whether Energy Trust should concentrate efforts in the residential market or on the commercial market. The results slightly tilted to the residential side, but the overall feedback was to stay on the current course. This will be included in the budget action plan. The budget is smaller in 2018, and there will be fewer projects with substantially higher above market costs for residential projects. We also asked how often to communicate about our plans and about legislative information that we receive, and feedback was to communicate early but stay flexible. The council also expressed that the non-incentive work we do is valuable. Next year will be critical to support businesses and trade allies. Quality standards and consumer protection are important. Ideas about a Solarize 2.0 for residential projects also emerged from the feedback.

We also heard from Renewable Energy Advisory Council that we need to be ready for what is coming next by getting more custom and targeted deployments. With new technology coming into the market, we need to maximize the value of solar systems. Other ideas included storage, peak management, smart inverters, community solar, equitable access to solar and expanding participation.

Dave presented an overview of the 2018 Solar action plan, which aims adapt to market changes, continue focus on soft-cost reduction and industry development, focus on solar projects with higher utility value, focus on broadening access to solar, and prepare for a future where solar incentives are less standard and more custom or targeted.

While the current trend for next year shows above-market costs rising, we believe that above-market costs will decline in the long run. The timeline may be pushed out for residential, and it is still happening in the commercial market.

Dave outlined how the Solar program plans to adapt to market changes. Staff plans to moderately increase residential and commercial incentives after RETC expiration; refocus and simplify standard commercial incentives and target smaller commercial projects; implement a streamlined custom incentive track to support larger or higher value projects; partner with utility grant programs; and allocate a small portion of the incentive budget for more targeted efforts. For the residential side, there is some above marke- cost headroom. We are looking at more incentives and would like feedback.

Alan Meyer: Have you considered maintaining the incentive where it is and wait to see whether it materialized so that you’re not overpaying in winter months?
Dave McClelland: Yes, we will watch this topic very carefully as legislative concepts emerge. We should know our direction by January or February 2018.

A portion of the budget will be devoted to commercial small projects. About two-thirds of our commercial projects make up about a third of the commercial budget. Standard commercial incentives are focused on those projects. The intention is to reserve funds for a more streamlined custom process, which would allow us to target some larger projects or higher value projects. We have received the green light from the OPUC to co-fund projects with the utility grant program, but we need to be careful about not overfunding projects.

Erik Anderson: If a commercial project is over the threshold, would you fund up to the available amount?
Dave McClelland: We currently have a hard cap at 100 kilowatts for customers of Pacific Power and 250 kilowatts for customers of PGE. We have received feedback from the council and trade allies. We need to balance the incentives and ensure that we are supporting projects that have above-market costs.

We would like to allocate a small portion of the incentive budget for some targeted efforts. On the commercial side, we are looking at a standard option and opportunities to be more targeted in our custom track. On the residential side, we’d like to consider some options where we have above market headroom.

In 2018, we plan to continue to collaborate with utilities on demand-side management efforts and provide project development assistance to customers and community members in scoping solar + storage for resiliency. In addition, Jeni Hall has been testing project development assistance for customers for renewable energy projects.

Michael O’Brien: What tools does Pacific Power use to identify where solar is a good fit for the load curve?

Erik Anderson: It's pretty a traditional transition and distribution upgrade analysis to see when we've identified a capital upgrade, to check peak times and decide whether solar can help solve the problem. It isn't new technology, but a new way to look at the issue to see where solar might help.

In 2018, Solar program staff to explore and test incentive offering targeted at advanced solar systems that manage peak with controls and integrated storage or flexible loads. The program also plans to develop communication materials for customer interested in solar and storage.

John Reynolds: Is there a standard size of storage?
Jeni Hall: We're learning more about storage, and we will be able to answer that question going forward. Right now, the most common system of installation is the power wall.
Jason Zappe: We have received a fair number of systems that are essentially power walls. We have had almost 10 customers who want to use standalone batteries where there is no other existing generation on site and are all power walls.

Dave McClelland: Do those customers net meter?
Jason Zappe: Batteries don't qualify, so we're basically doing this outside of the net metering rules and all the customers have attested that it is backup only. We put them through the interconnection process because they are charging from the grid, but we're really just supplying them with an interconnection agreement and no compensation for any kind of backup because there currently isn't any method to do that.

Michael O'Brien: Is there any commonality between these people?
Jason Zappe: Some customers are in unreliable areas and have frequent outages, so they use the battery as backup.

Dave noted other areas on the horizon for 2018 are to provide broader access to solar by continuing work with stakeholders to develop strategies for low- and moderate-income customers and to support workforce diversity through outreach and sponsorships. We're also interested in exploring and testing an incentive offering targeted to moderate income-customers and opportunities for low- and moderate-income homeowners.

Heather Eberhardt: When I was at the solar conference, I heard a trend that the credit scores of solar applicants has declined in the last few years. As you're looking at the moderate-income customers, can you track that in your applications?
Dave McClelland: Part of exploring and testing this is to figure out how you measure the moderate-income customer and what qualifies. We have a Savings Within Reach program but need better data.

Alan Meyer: I'm pleased to hear we're looking more holistically at efficiency and renewable programs to explore how we can help customers more effectively reduce their costs and create more opportunity to look at the challenge outside of silos.

Michael O'Brien: Are community benefits identified by a certain group or is Energy Trust evaluating at what you think they might look like?
Dave McClelland: We're at the very early stage of consideration. We're interested in feedback on what community benefits should apply. If there are projects that align with our low- and moderate-income strategies, we'll be interested to explore those avenues. We've also been doing work with the City of Portland and other municipalities around resiliency.

Suzanne Leta-Liou: From my perspective, a lot of this is numbers play, so it's hard to give guidance to the extent that I don't have that information in front of me and you have a very limited budget.

There's also a fine balance between deploying projects to the best you can in the residential, commercial and low- and moderate-income markets and testing out new technology. I struggle with that given the current rate design and metering construct and that we're not getting storage to pencil in Oregon. I worry that a large part of the budget is focused on that. Given the constraints we have, would the funds be better spent deploying projects?
Dave McClelland: The numbers we have been using are at 3-5 percent of the total budget, so we're not talking about spending a large amount of funds. If we reduce volume by 5 percent, is that worth it and what is the trade off? We will be coming back with numbers next month. As of now, we're looking at less than $6 million in incentives for next year.
Jed Jorgensen: From my perspective, it's hard to learn without trying new things.
Dave McClelland: Sometimes a recession is a good opportunity to re-tool your business for the future. Similarly, we are expecting half the volume in projects next year. It allows us to do a relatively small push somewhere that could have a bigger impact on the market as you have the opportunity to grow that option.

Suzanne Leta-Liou: I noticed you're planning on some new custom incentives. Where does large commercial fit?
Dave McClelland: It would fall into the custom track. A challenge we've had this year, and the reason we had to implement a side path, is that we were getting projects at that scale with relatively low cost that were really pushing above-market costs. This custom track would allow us to look at projects in more detail that would confirm we're supporting projects that have above-market costs. It will be a balancing act because we're working with relatively small amounts of money and it won't be a continuous offer each month. For Pacific Power in particular, our budget is very constrained.

Suzanne Leta-Liou: So you're thinking of systems over 100 kilowatts?
Dave McClelland: It could also be smaller systems that bring other value, and any customers that wants to take both an Energy Trust incentive and a utility grant.
Suzanne Leta-Liou: Did the OPUC make a final decision on that?
JP Batmale: Yes, there was a request to clarify what constitutes a nonprofit, and a clarification on the rules around when the commission could approve incentives for a for-profit company. The outcome was that there could be comingling of funds when the entity receiving the voluntary funds is of a certain type of nonprofit. The utilities have a pathway for issuing exceptions to for-profit companies for new projects that are deemed to be in the public interest. For-profit firms can apply for these funds but need to be vetted by the utilities and approved by the OPUC.

4. Public Comment
There was no public comment at this time.

5. Meeting Adjournment
Jed Jorgensen adjourned the meeting at 11:30 a.m. The next scheduled meeting of the Renewable Energy Advisory Council is on October 25, 2017.

Opal Springs Hydropower Project

Board of Directors Meeting
July 20, 2016

Energy Trust of Oregon

Presentation summary

Project context

Detail about this project

Above-market cost evaluation

Proposed incentive and REC terms

Overall project summary

- Install inflatable weirs on existing dam, raising pool six feet
- Install fish ladder at dam
- Six feet of increased head will generate an additional ~3,227 MWh / yr.

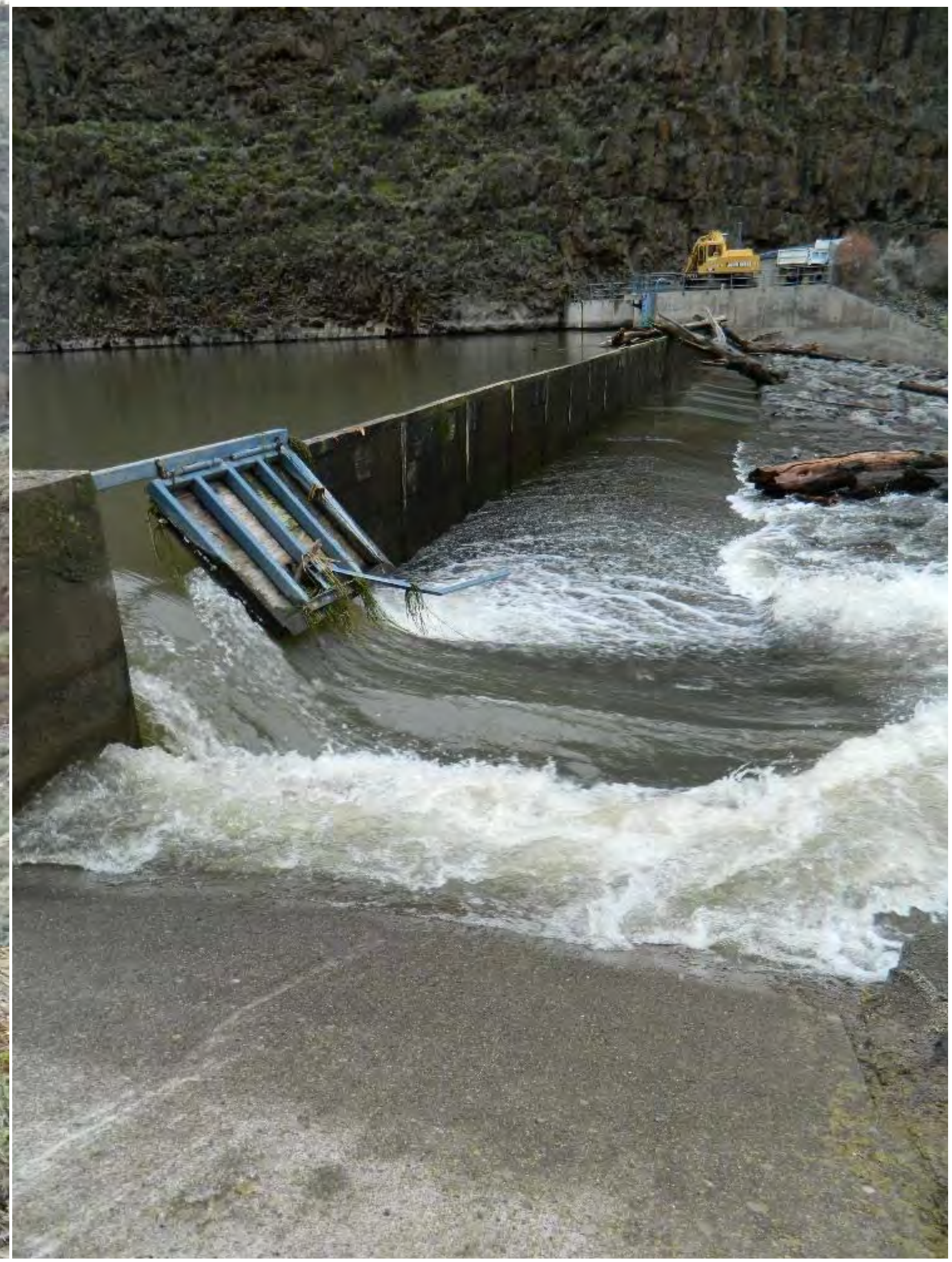
Deschutes Valley Water District

- Municipality – potable water supplier
- Existing Hydropower Project (~28,000 MWh / yr.);
- PPA w/ PAC expires 12/31/2020

Fish passage

- Pelton-Round Butte Hydro Projects - fish passage in 2007
- FERC license → expires 2032
- 2012 Settlement Agreement
- Low Impact Hydropower Institute (LIHI) Certification

Obermeyer inflatable weir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Review points

- Site control
- Development and operational team expertise
- Permitting
- Interconnection
- Power purchase agreement

Review points

- Energy assessment
- Energy conversion technology
- Project revenues
- Project capital costs
- Financing, grants, and incentives

Separating Out Project Costs

Development & Install Costs	Total Cost	Energy Costs	Notes
Fish ladder & spillways	$ 2,691,783	$ -	Deleted
Earthwork / dewatering	$ 1,370,747	$ 685,373	Reduced by 50%
Foundation / sediment removal	$ 55,391	$ 27,696	Reduced by 50%
Diversion dam / gates	$ 2,304,201	$ 1,152,101	Reduced by 50%
Powerhouse / wiring	$ 298,636	$ 298,636	Energy cost
Intake structure	$ 632,681	$ 632,681	Energy cost
Interconnection/Transmission	$ 150,000	$ 150,000	Energy cost
Dated construction estimate cost escalation (4% per year, two years)	$ 600,041	$ 324,465	Reduced by $275,576 directly related to fish passage
Total project development costs	$ 889,243	$ 444,622	Reduced by 50%
Energy Trust PDA	$ (191,134)	$ (191,134)	
Total upfront costs	**$ 8,801,589**	**$ 3,524,439**	

Grants

Grants	Total Grants		Energy Grants		Notes
ODFW - Fish passage, awarded	$	1,200,000	$	-	Deleted
OWEB - Fish passage, awarded	$	2,000,000	$	-	Deleted
Blue Sky - Energy, applied	$	400,000	$	400,000	Energy grant
Total	**$**	**3,600,000**	**$**	**400,000**	

Above-market cost

Project Financial Summary - Present Value Basis - Evaluated over 20 years	
Project Costs - Energy Only	
Total Design & Construction - Energy Only	$ 3,524,439
Grants - Energy Only	$ 400,000
Equity: Total Design & Construction - Grants	$ 3,124,439
Expenses	
NPV Total Project Expenses - Energy Only	$ 181,651
Total cost: Equity + Expenses	**$3,306,090**
Revenue	
NPV Revenues	$ 2,471,541
Above Market Cost: Total Cost - Revenues	**$ 834,549**

Proposed incentive

Evaluation Criteria	
Project Term:	20 Years at 8% discount rate
Above-Market Cost (NPV):	$834,549
Proposed Incentive:	$750,000
Payment Terms:	Two payments of $375,000
NPV Incentive	$668,724, 80% of AMC
REC Allocation:	64,540 total over 5 years (100% of expected incremental generation)
REC Value:	$11.62 per REC
Energy Value:	$2.04 million per aMW

Comparison to past projects

Project	**Cost per aMW**	
COID Juniper Ridge Phase 1	$	652,028
Klamath Irrigation C-Drop	$	1,228,154
Opal Springs Hydro	***$***	***2,035,946***
Three Sisters Irrigation District	$	2,825,806
Swalley Irrigation District	$	2,916,985
Farmers Irrigation District (LDPP)	$	3,767,742

Timeline

- Construction contracting – summer 2016
- Final permitting – early 2017
- Construction mobilization – spring 2017
- PPA negotiation – 2016/2017
- Commissioning – November 2018

Permitting

- Right-of-Way Permit to occupy additional BLM land
- Non-capacity amendment to DVWD's FERC license
- Water Quality Certification
- Existing Water Right Permit (S-47591) modification
- Fish passage waiver
- Section 404 dredge and fill permit

Conclusion

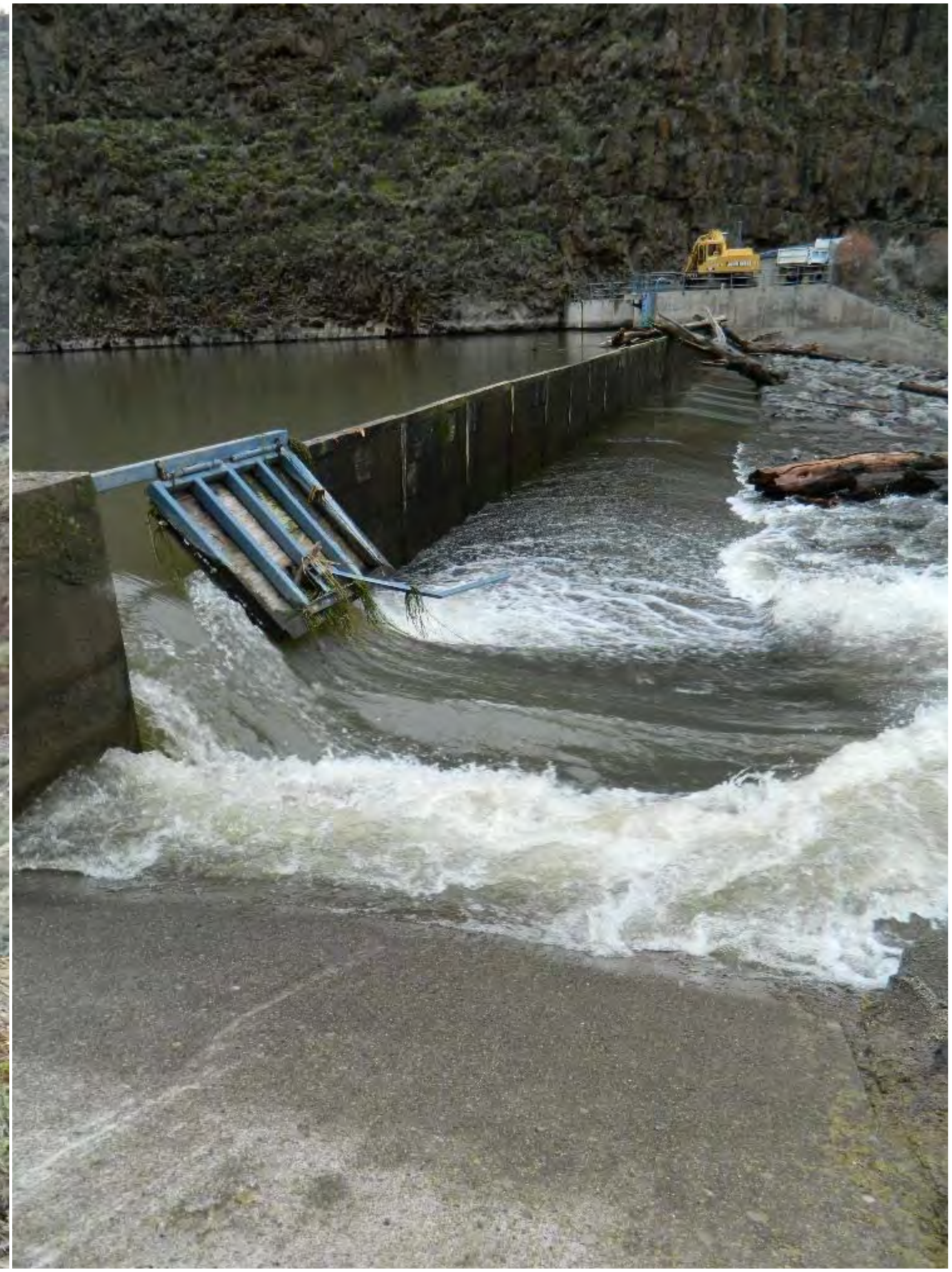
Questions?

Opal Springs Hydropower Project - revised

Renewable Energy Advisory Council

October 25, 2017

Energy Trust of Oregon



Grants

Fish Passage Grants	Total Award	AMC model
ODFW - Fish passage, awarded	$ 1,200,000	Not included
OWEB - Fish passage, awarded	$ 2,000,000	Not included
OWRD - Fish passage - recommended	$ 1,550,486	Not included
Total grant funds accounted for	**$ 4,750,486**	

Capital Costs - hydropower

Development & Install Costs	2016 Energy Related Costs	2017 Total Project Costs (Kleinschmidt)	2017 - Energy Related Costs	Notes
Earthwork/Access/Mobilization/Dewater	$ 685,373	$ 725,802	$ 362,901	Reduced by 50%
Fish ladder	$ -	$ 7,000,000	$ -	Deleted
Spillways	$ -	$ 298,280	$ -	Deleted
Diversion dam and gates materials	$ 225,120	$ 80,000	$ 40,000	Reduced by 50%
Intake structure	$ 172,069	$ 30,000	$ 30,000	PURE ENERGY COST
Powerhouse/electric/gate wiring	$ 298,636	$ 120,000	$ 120,000	PURE ENERGY COST
Foundation shoring / sediment removal	$ 27,696	$ 66,469	$ 33,235	Reduced by 50%
Diversion dam and gate equipment	$ 926,981	$ 763,720	$ 381,860	Reduced by 50%
Intake structure equipment	$ 460,612	$ -	$ -	PURE ENERGY COST
Interconnection/Transmission	$ 150,000	$ 150,000	$ 150,000	PURE ENERGY COST
Two year cap-ex escalation ($600k)	$ 324,465		$ -	Deleted
Total project development costs	$ 444,622	$ 1,636,214	$ 409,053	Reduced by 75%
Energy Trust PDA	$ (191,134)	$ (191,134)	$ (191,134)	
Total upfront costs	**$ 3,524,439**	**$ 10,679,351**	**$ 1,335,915**	
Grants	**Energy Related Grants**	**Total Project Grants**	**Energy Related Grants**	**Notes**
ODFW - Fish passage, awarded	$ -	$ 1,200,000	$ -	Deleted
OWEB - Fish passage, awarded	$ -	$ 2,000,000	$ -	Deleted
OWRD - Water Project Grants	$ -	$ 1,550,486	$ -	Deleted
Blue Sky - Energy, applied	$ 400,000	$ -	$ -	No Blue Sky award
Total grant funds accounted for	**$ 400,000**	**$ 4,750,486**	**$ -**	
Upfront costs minus grants	**$ 3,124,439**	**$ 5,928,865**	**$ 1,335,915**	

Proposed incentive

Evaluation Criteria	
Generation:	1,010 MWh / year
Project Term:	20 Years at 8% discount rate
CapEx:	$1,335,915
Above-Market Cost (NPV):	$881,341
Proposed Incentive:	$450,000
Payment Terms:	Two payments of $225,000
NPV Incentive	$401,235
REC Allocation:	100% (20,200 total over two years)
REC Value:	$22.28 per REC
Energy Value:	$3.9 million per aMW

Conclusion

Questions?

Watson Hydropower Demonstration Project

Renewable Energy Advisory Council

October 25, 2017

EnergyTrust of Oregon

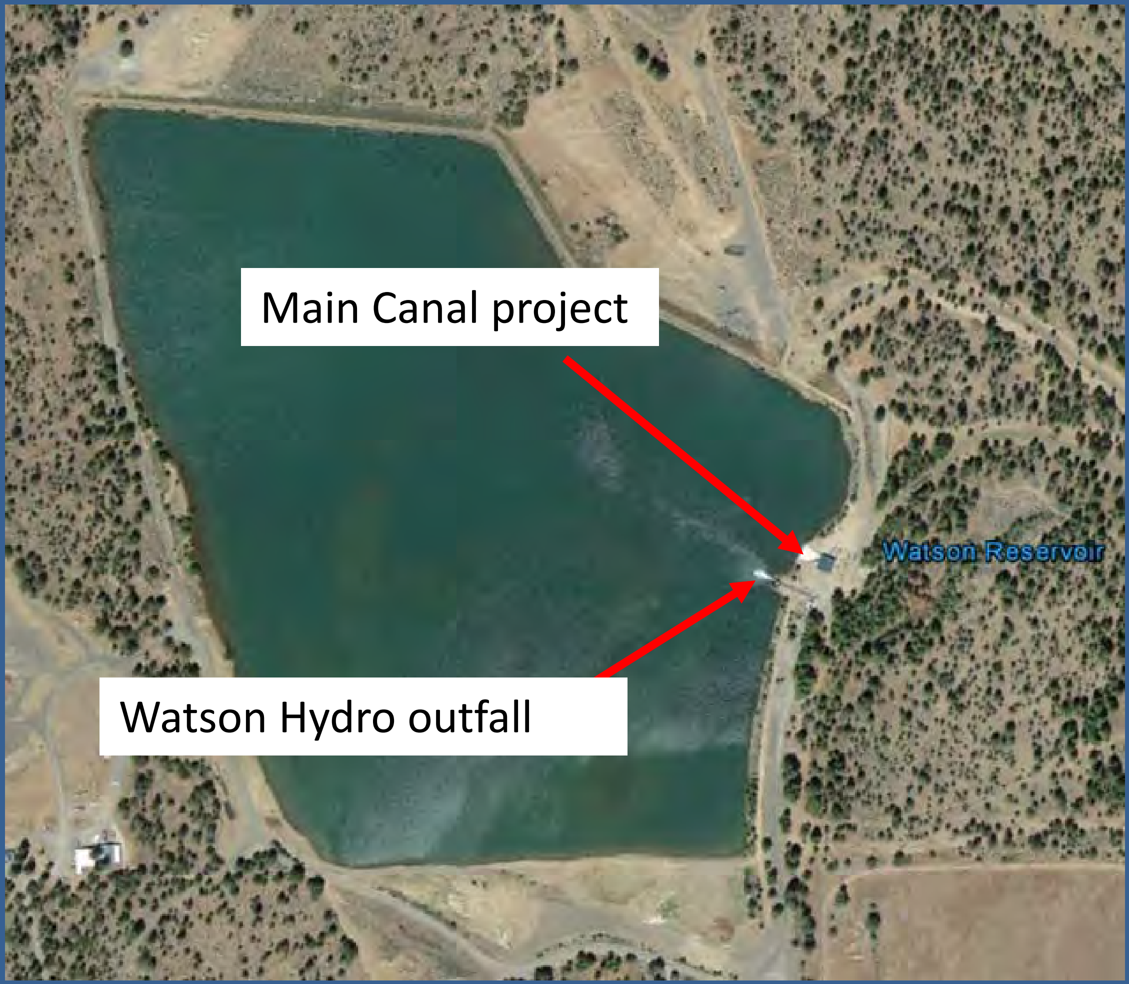
Summary

- ❑ Project background & detail
- ❑ Project evaluation
- ❑ Above-market cost assessment
- ❑ Proposed incentive and REC terms

Three Sisters Irrigation District

- About three miles SE of Sisters, Oregon
- TSID: Municipality – irrigation water supplier
- Overall purpose → harness RE from existing irrigation flows & demonstration project

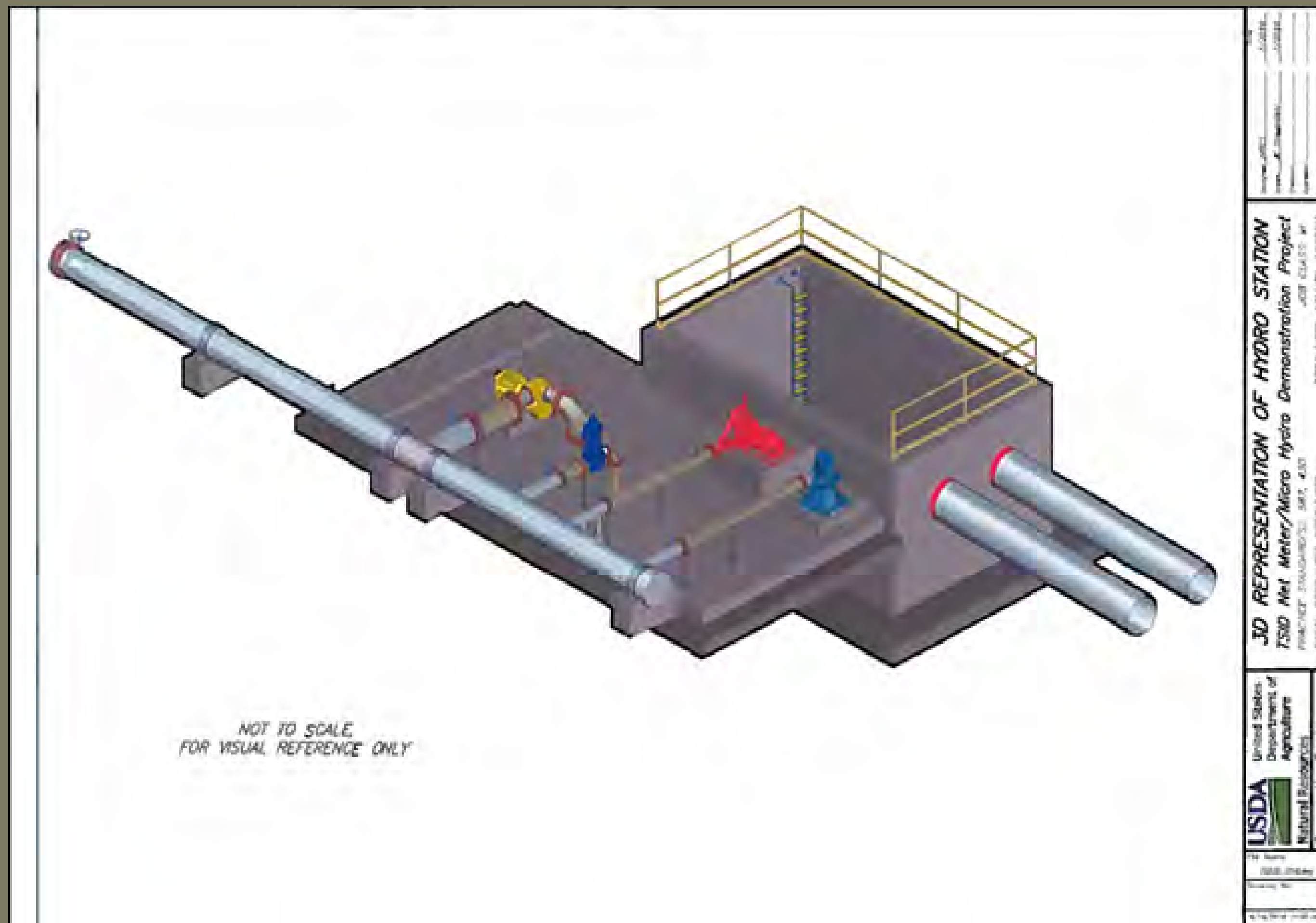
Watson Hydro Project



- Micro-turbine demonstration project
- Existing penstock
- Using available water (up to 20 cfs) at main canal project
- Generate an additional ~807 MWh / yr.

Watson Hydropower Project

- Net head of 163 - feet – 70 psi at manifold
- 20 cfs maximum
- Four turbines – 189.5 kW
- Operation – March through October



Review points

- Site control
- Development / operational team expertise
- Permitting
- Interconnection
- Power purchase agreement

Energy Assessment

Theoretical max generation				
Month	Hours	Flow	Head	Generation (kWh)
April	720	20	163	198,747
May	744	20	163	205,372
June	720	20	163	198,747
July	744	20	163	205,372
August	744	20	163	205,372
Sept	720	20	163	198,747
Oct	372	20	163	102,686
	4,764			1,315,041
15 days of operation in October				

TSID projected generation			
Turbine	Power Gen (kW)	Annual hours	Generation (kWh)
HydroTek	149.2	5,000	746,000
Soar	17.4	4,000	69,600
Cornell	13.2	4,000	52,800
Canyon	9.7	4,000	38,800
	189.5		907,200

Expected generation			
Turbine	Power Gen (kW)	Annual hours	Generation (kWh)
HydroTek	149.2	4,764	710,789
Soar	17.4	2,382	41,447
Cornell	13.2	2,382	31,442
Canyon	9.7	2,382	23,105
	189.5		806,783

Review points

- Energy conversion technology
- Project revenues
- Financing, grants, and incentives
- Project capital costs

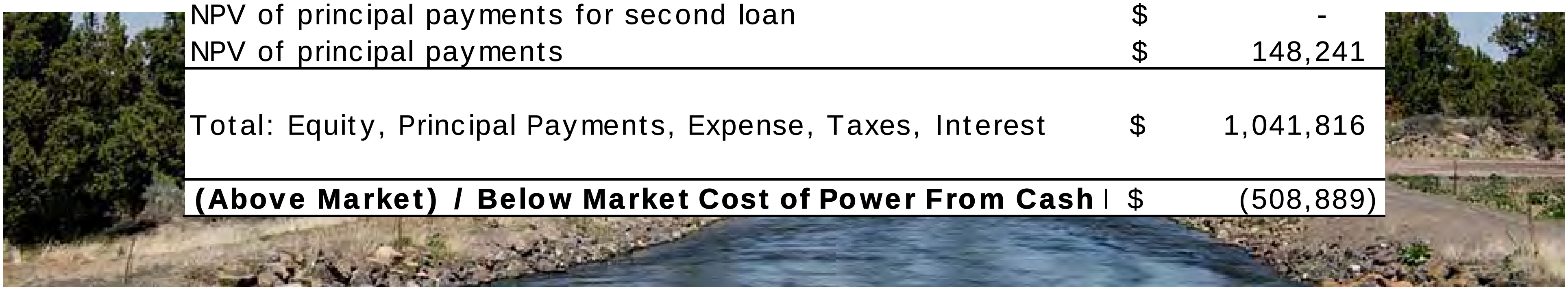
Capital Cost

Turbine Manufacturer	Cost	Type	Generator Nameplate (kilowatts)
Cornell	$15,000	Pump as turbine	15.0
Soar	$25,000	Francis	22.4
Canyon	$30,560	Pelton	11.2
HydroTech	$130,000	Francis	150.0
Total	**$200,560**		**198.6**

Item	Estimated Expense
Building materials	$150,000
Controls	$75,000
Interconnection	$70,000
Electrical engineering	$20,000
Electrical install-labor	$50,000
NRCS engineering	$25,000
Turbine-generator install-labor	$10,000
Legal & permits	$6,500
Security and tech	$5,000
Valves and piping	$35,000
subtotal	$446,500
Contingency (~~$10,000~~)	$44,650
Total	**$491,150**

Above-market cost

ETO assigned project risk adjusted rate of return		8.0%
Project Cost		
Total Design & Construction	$	691,710
Debt	$	-
Grants	$	110,950
Equity	$	580,760
Revenue		
NPV Revenues	$	532,927
NPV Energy Trust Subsidy	$	-
NPV Total Revenues	$	532,927
Expense		
NPV Total Project Expense	$	312,815
NPV Total Project Taxes	$	-
NPV of interest payments for all loans	$	-
NPV of principal payments for second loan	$	-
NPV of principal payments	$	148,241
Total: Equity, Principal Payments, Expense, Taxes, Interest	$	1,041,816
(Above Market) / Below Market Cost of Power From Cash	$	(508,889)



Proposed incentive

<u>Evaluation Criteria</u>

Generation:	807 MWh / year
Project Term:	20 Years at 8% discount rate
CapEx:	$691,710
Above-Market Cost (NPV):	$508,889

Proposed Incentive:	$360,000
Payment Terms:	Three payments of $120,000
NPV Incentive	$309,251
REC Allocation:	100% (16,140 total over 20 years)
REC Value:	$22.30 per REC
Energy Value:	$3.91 million per aMW

Comparison to past projects

Project	**Cost per aMW**
COID Juniper Ridge Phase 1	$ 652,028
Klamath Irrigation C-Drop	$ 1,228,154
Opal Springs Hydro	***$ 3,902,970***
Three Sisters Irrigation District	$ 2,825,806
Swalley Irrigation District	$ 2,916,985
Farmers Irrigation District (LDPP)	$ 3,767,742

Timeline

- Construction contracting – fall 2017
- Final permitting – fall 2017
- Construction– winter 2017 through spring 2018
- Commissioning – late 2018

Thank You

Questions?

EnergyTrust of Oregon

McKenzie Hydropower Project

October 25, 2017

Summary

Authorize up to $640,000 paid over six or more payments, to offset the above-market cost of the 300kW McKenzie hydroelectric facility proposed by the Three Sisters Irrigation District (District) near Sisters, OR. The District proposes a facility near the McKenzie reservoir to take advantage of excess pressure in new, pressurized water supply pipes, part of a long-term Irrigation Modernization strategy, and generating an expected 922 megawatt hours (MWh) annually for delivery to Portland General Electric or Pacific Power.

Energy Trust Goals

- The McKenzie project supports Goal 2 of the 2015-2019 Strategic Plan: to accelerate the rate at which renewable energy resources are acquired. The project also supports Strategic Plan Strategies focused on building relationships with outside organizations around projects with multiple benefits that support and enable collaborative investments.
- This project will add to the portfolio of 15 operational hydropower projects Energy Trust has supported, currently representing 8.1 MW of capacity and 3.3 average megawatts (aMW) of generation.

Background

- In May, 2017 Energy Trust announced a competitive process to allocate up to $3.0 million in incentives for certain types of renewable energy facilities in Portland General Electric service territory and $1 million in Pacific Power territory. A total of three applications were received, all hydropower projects, including the McKenzie project. Funding was dedicated for the other two projects at a staff level as the incentives were less than $500,000. One of the other projects is also under development by the District, a 200kW facility awarded $360,000, delivering power to Pacific Power.
- The District is an agricultural water provider working to modernize its delivery system. By replacing irrigation canals with pressurized pipe, the district can conserve water by eliminating seepage and evaporation. Pressurized water eliminates on-farm pumping and the District can generate hydropower where there is excess pressure.
- Energy Trust has funded projects with the District in the past: a 700kW hydroelectric turbine in 2014. The piping in that project restored 21.6 cubic feet per second (cfs) of water to Whychus Creek, a tributary of the Deschutes River. The 700kW turbine has performed well, meeting generation expectations even during drought years.
- The proposed McKenzie project will take advantage of a new 5.25-mile long pressurized penstock pipeline that discharges into the McKenzie Reservoir. Water savings from the new pipeline permanently restores 7 cfs of flow back into Whychus Creek, benefiting threatened and endangered fish species.
- The pipeline creates 101-134 feet of head for the hydro project. Flows through the pipes range from 10-40 cfs during the irrigation season from March to November. Irrigation season

water flows tend to follow a bell curve, ramping up and down at the beginning and end of the season.

- Similar to the first hydro facility, the District intends to construct a 30'x30' concrete powerhouse and install a 300kW horizontal Francis turbine with an estimated generation of 922,400 kWh, annually. Power generated by the project would be wheeled through Central Electric Coop (CEC) and Bonneville Power Administration (BPA) for delivery to either Portland General Electric (PGE) or Pacific Power.
- The District has been working under the intention of delivering to PGE because PGE's power rates are better, at present, than Pacific Power's. In recent weeks, however, the District discovered an issue related to how PGE processes scheduled power that may mean it is not feasible for them to deliver power to that utility. The district is working with PGE to resolve the issue but if no resolution is forthcoming, it will deliver power to Pacific Power instead. Above-market costs for the project, as is noted below in this memo, are very similar regardless of utility.
- Project construction is expected to begin in spring 2019. The District anticipates commissioning and testing to start in in winter 2019 with commercial operation occurring in spring 2020.

Staff Evaluation

For projects eligible for incentives, Energy Trust staff thoroughly evaluate the following prior to performing an above-market cost analysis:

- Site control
- Development and operational team expertise
- Resource assessment
- Energy conversion technology and estimated generation
- Permitting
- Interconnection
- Power purchase agreement
- Project capital costs and operational and maintenance expenses
- Financing
- Project revenues

Staff's evaluation found the following:

Site control, Development Team, Resource and Generation Estimates, and Permitting

- The District has site control, a proven team capable of executing on project development, and the experience to operate the project when complete.
- The head and flows available support the estimated generation and the chosen turbine technology is a good fit for the resource.
- The District has successfully engaged in the required local, state, and federal permitting processes and we have no concerns about the District's ability to complete permitting activities in time for construction.

Interconnection

- The project is located in the service territory of Central Electric Co-op (CEC) and will physically interconnect to a CEC distribution line that runs near the proposed powerhouse site. From there, CEC will move the power to a BPA substation and BPA transmission infrastructure will deliver the power to PGE or Pacific Power.

- The District has submitted an interconnection application with CEC and has met with both BPA and CEC staff to discuss interconnection needs. A systems impact study is underway by CEC to evaluate any changes within the distribution or transmission system related to the project. The district will be responsible for paying for any upgrades that are necessary.

- Since the interconnection study has not yet been completed, costs for the interconnection are engineer estimates, not utility quotes. The interconnect cost is estimated at $115,000. Compared to the 700 kW unit, where interconnection costs were approximately $250,000, the estimate seems reasonable but there is risk associated with not knowing the final costs of interconnection.

- To wheel the project across their service territory CEC will charge the District a flat rate of $6.24 per kW per month, resulting in an annual cost of $22,464. The charge is levied for 12 months, an industry standard, despite the fact that the project will only be online during the irrigation season.

- The District also has to move power through BPA. If the District delivers to PGE this requires firm, point-to-point transmission services, which they have secured. These services result in an annual charge of approximately $21,600. If, instead, the district delivers to Pacific Power, the fees are lower because BPA shares a substation interconnection with the utility in the local area. Under this scenario the annual BPA fee is reduced to $6,000. There is also a compensatory reduction in power rates, discussed below.

<u>Project Costs, Expenses, and Financing</u>

- Total capital costs are approximately $1.43 million, the largest single cost being the hydro turbine. Interconnection costs are engineering estimates that appear reasonable.
- To be conservative Energy Trust staff added a 10% contingency in case interconnection or other costs run higher than expected. Past experience has shown, for myriad reasons, that most project's experience higher-than-expected final costs.
- The wheeling charges, regardless of the final delivery utility, are a large part of the overall project's annual cost. Since TSID will own and operate the facility, day-to-day maintenance and operation will be performed by in-house contractors, similar to the 700 kW project. Therefore, the estimated operations cost stays relatively low. The estimated O&M cost also includes $5,000 for insurance and a $5,000 capital reserve accrual beginning after year 10 of operation.
- The District intends to utilize a $125,000 loan from the Clean Water State Revolving fund to cover upfront costs that are not being paid for with equity or grants. The loan has an interest rate of 1.94% and includes 50% forgiveness. Due to the 50% loan forgiveness, staff considered $62,500 as a grant and treated only the other half as a standard loan.
- The cost for construction of TSID's penstock, which has already been installed, is not considered in the Above Market Cost calculations.

Capital Costs

<u>Engineering</u>		
Electrical	$	60,000
Structural	$	25,000
Hydro Plant	$	50,000
<u>Materials</u>		
Powerhouse	$	200,000
Turbine and Generator Package	$	395,000
Turbine inlet, Bypass valves, Interconnection valves	$	35,000
Interconnection (transformer, line, physical)	$	115,000
Controls	$	80,000
Security	$	25,000
<u>Labor</u>		
Powerhouse Construction	$	175,000
Electrical Installation	$	80,000
Turbine Generator Installation	$	10,000
<u>Miscellaneous</u>		
Legal, Permits, and Insurance	$	35,000
Fuel, Supplies, and Materials	$	10,000
NEPA processes - Environmental Impact	$	5,000
Contingency (Added by Energy Trust)	$	130,000
Total Estimated Cost	**$**	**1,430,000**

Estimated Annual Operations & Maintenance Costs

Operations/Maintenance/Repairs	$	2,500
Materials/Supplies	$	600
Transmission scheduling	$	1,200
Wheeling and Transmission Charges		
BPA	$	21,600
CEC	$	22,464
Insurance	$	5,000
Capital Reserves	$	5,000
Total	$	57,164

<u>Grants and Revenues (including Power Purchase Agreement)</u>

- The District has received significant grants for this project, including $175,000 for a Renewable Energy Development Grant (RED) from the Oregon Department of Energy (ODOE) and a $400,000 WaterSmart grant from the Bureau of Reclamation (BOR).
- The project is outside the service territories of both PGE and Pacific Power. Avoided cost rates available to wholesale Qualifying Facilities are very low for both Pacific Power and Portland General Electric but, at present, PGE's rates are about 25% more favorable. Thus, the District chosen to try to deliver power to PGE.

- Using the expected 922 MWh of generation annually and PGE's current Schedule 201 rates, the project's revenue range from $20,722 in year one to $100,503 in year twenty. Without an incentive from Energy Trust, the project will not pay back within 20 years.
- If the project delivers to Pacific Power, the beginning and ending revenue streams are similar to PGE. The difference is that PGE's rates go up starting in 2025 while Pacific Power's rates stay low until 2028. The three years of lower rates under Pacific Power's Schedule 37 largely offsets the benefit of the reduced BPA wheeling fees.

Staff's overall evaluation:

- The project is viable but has above-market costs due to the low power rates that are currently available.
- The project has completed its design phase and faces no significant permitting challenges.
- The project has significant strengths: it will be constructed by an entity with an existing hydropower project; it is municipally owned; and the District has secured grants for the project.
- Three Sisters is a returning customer and has a proven track record as a well-organized, successful hydropower operator.
- Overall, the project has few risks.

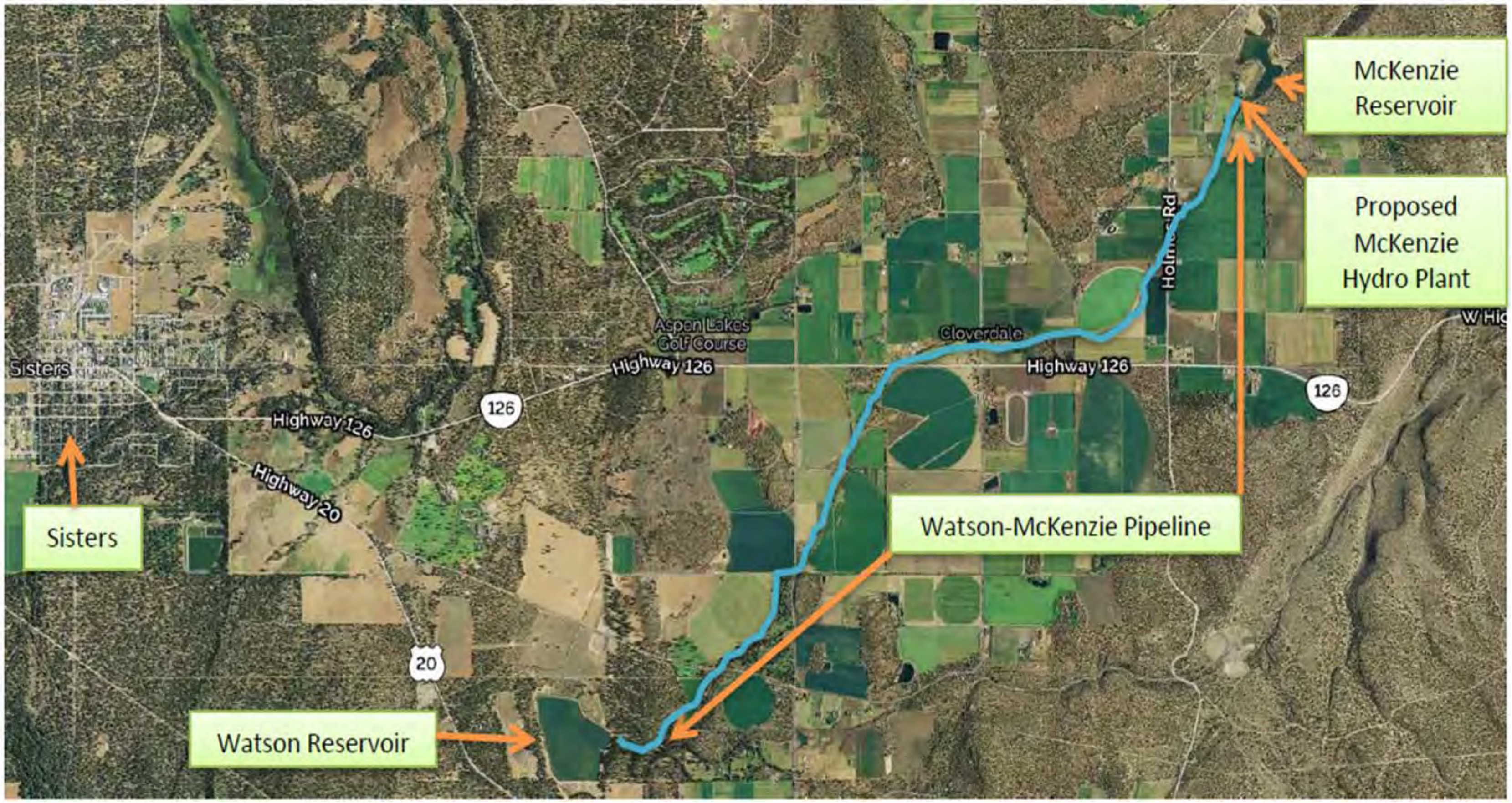
Staff also contracted with Evergreen Energy to provide an independent evaluation of the project. Evergreen has broad experience in renewables and has provided many similar reviews for Energy Trust in the past. Their review concurred with staff's assessment and recommended supporting the project with an incentive.

Above-Market Cost Analysis and Proposed Incentive

- The above-market cost is calculated as the difference between the cost to produce the power over a specific term, and the market value of the power. Above-market costs are calculated on a present-value basis: all costs and revenues over the project term are discounted to their current value as if they existed today.
- Staff evaluated this project over a 20-year term. The length of the term was chosen to match what we have used for similar hydro projects.
- The project was evaluated at an 8% discount rate, consistent with the 8-10% range of discount rates Energy Trust has applied when evaluating other municipally or government-owned projects.
- The table below shows the financial summary for the project if it delivers power to PGE. There are minor differences if the project delivers to Pacific Power instead, but the overall financial picture is very similar.

Project Financial Summary - Present Value Basis - Evaluated over 20 years		
Project Cost		
Total Design & Construction	$	1,430,000
Expense		
NPV Total Project Expense	$	444,674
NPV of interest payments	$	8,064
NPV of principal payments	$	29,247
	$	481,985
Total cost: Cost + Expenses	**$**	**1,911,985**
Revenue		
NPV Total Revenues (including avoided O&M)	$	1,133,126
Above Market Cost: Total Cost - Revenues	**$**	**(778,859)**

- The project's above-market costs total $778,859 (NPV) if it delivers to PGE. The above-market cost if it delivers to Pacific Power is slightly less at $729,917.
- Staff proposes to provide an incentive of $640,000, split into payments over time. The first payment would be the largest, $440,000, payable upon reaching commercial operation. Upon meeting annual generation milestones, staff would propose to make additional payments of $40,000 annually, over five years if the project delivers to PGE. If the project delivers to Pacific Power we propose additional payments of $25,000 a year, for eight years. The series of payments over time would serve to help the District maintain a positive cash flow during the very lean early years of their PPA, where power prices are less than $30/MWh. With the Energy Trust incentive, the project would pay back in 15 years.
- On a present-value basis, Energy Trust's incentive is worth $540,431 to $558,286 (depending on how many additional payments are made), or ~70% of the project's above-market cost. At $6.1 million/aMW the incentive is in the upper end of the range of incentive costs for hydropower projects we have supported in the past. This is due to low power prices, which require larger incentives to enable projects to be financially viable.
- Energy Trust would ask for 18,448 Renewable Energy Certificates (RECs) from the project, equivalent to 100% of the expected generation produced by the project over 20 years.
- The REC allocation goes beyond board policy requiring Energy Trust to take ownership of RECs in proportion to its contribution to above-market costs. Because the project requires an incentive in the upper range of costs, we think it is reasonable to request more RECs than we usually would, in this case 100% of the RECs.
- Staff proposes to negotiate a contract with the District with milestones to allow Energy Trust to withdraw funding if the project is unable to move forward.
- Funds for the project are within the 2017 Other Renewables program budget.


McKenzie Reservoir
Proposed McKenzie Hydro Plant
Watson-McKenzie Pipeline
Watson Reservoir
Sisters
Aspen Lakes Golf Course
Cloverdale
Highway 126
Highway 126
Highway 126
Highway 20
126
126
20
Sisters

- 300 kW Francis Turbine
- Annual Generation: 922,400 kWh/year
- Term: 20 years

- Head: 101 – 134 ft
- Flow: 10-40 CFS (Cubic Feet per Second)
- Estimated Commercial Operation: Spring 2019
- Operate: March – Nov.
- 30’X30’ concrete powerhouse

TSID Generation Estimates	ETO Generation Estimates
1,024,888 kWh	922,400 kWh

- FERC NOI ✓
- NEPA Environmental Exclusion ✓
- BPA Transmission Agreement ✓
- Existing Water Rights/Construction Permit

- **Central Electric Cooperative**
  - Flat rate: $6.24 per kW per month = $22,464 annually

- **BPA**
  - MOU
  - 1.9% line loss
  - Transmission services: $21,600 annually

- **PGE or PAC**
  - PGE: QF, Schedule 201
    - Avoided Cost: $ 20-$27 (2019-2024), $84.23 (2025)
  - PAC: QF, Schedule 37
    - Avoid Cost: $23-$32 (2019-2024), $87 (2028)

- $1.43 Million Capital Cost
- 10% Contingency added by Energy Trust
- $62,500 Clean Water State Revolving Fund Loan –DEQ (20% forgiveness)
- $175,000 Renewable Energy Grant – ODOE
- $400,000 Water SMART Grant – Bureau of Reclamation

- 2019 → $20,722
- 2025 → $77,691
- 2038 → $100,503

- Above Market Cost: $778,859
- 15 year payback, 3,1% IRR

- Purposed ETO Incentive: $640,000
  - $440,000 upon Commercial Operation
  - $40,000 a year for 5 years after Comm. Op.

- 100% RECs
- 18,448 RECs total
- $35/REC
- $6.1M /aMW

Irrigation Modernization Funding Partners

NRCS
U.S. Department of Agriculture
Natural Resources Conservation Service

The Nature Conservancy

Oregon Watershed Enhancement Board
OWEB

U.S. Department of the Interior
Bureau of Reclamation

Deschutes River Conservancy

National Fish and Wildlife Foundation
NFWF

National Forest Foundation

Oregon
Fish & Wildlife

Draft 2018 Annual Budget & 2018-19 Action Plan

October 25, 2017

Energy Trust of Oregon

Today’s Presentation

- Projected 2017 Results
- Budget Building Blocks
- Draft 2018-2019
  Action Plan Highlights
- Draft 2018 Budget
- Next Steps
- Discussion and Feedback

15 Years of Affordable, Clean Energy

$1.5 billion investment delivers these customer benefits:

More than 660,000 homes and businesses served

10,000 clean energy systems generating renewable power from the sun, wind, water, geothermal heat and biopower

$6.9 billion in savings over time on participant utility bills from their energy-efficiency and solar investments

20 million tons of carbon dioxide emissions kept out of our air

Projected 2017 Results

- Forecasting to exceed energy savings goals for 3 utilities
  - Strong activity in new construction and high demand for lighting
  - Shortfall for 2 gas utilities from project delays and delayed savings strategy
- Forecasting to exceed renewable energy generation goal
  - Strong standard solar plus completion of 2 larger-scale solar projects
  - Large pipeline of Other Renewables projects, including 3 hydropower projects expected in 2019

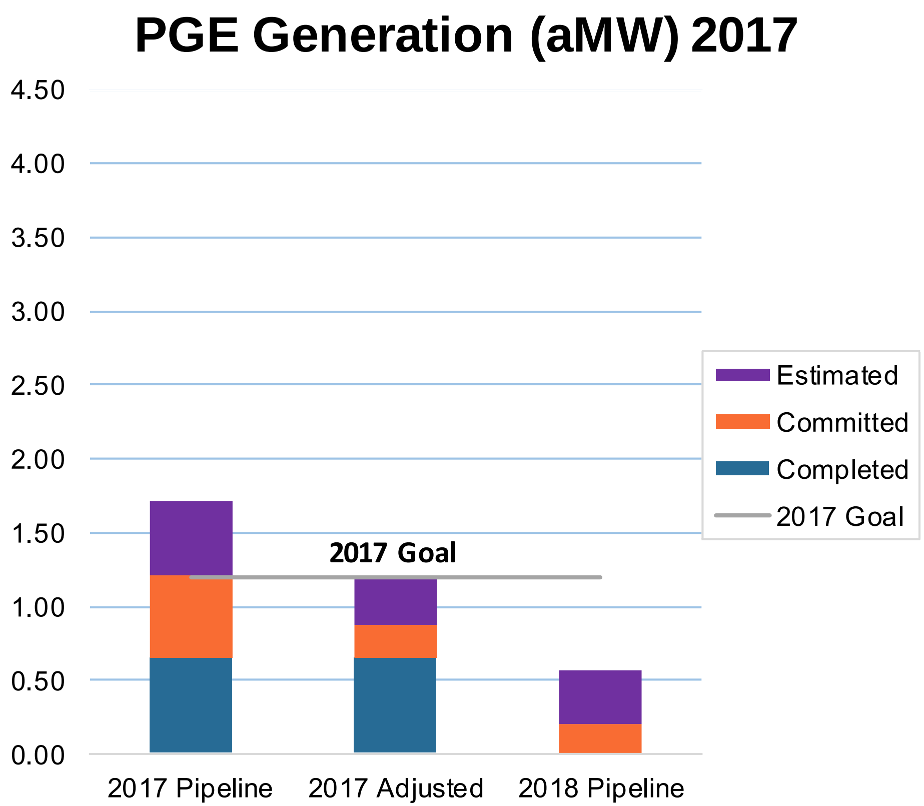
Q3 Renewables Dashboards

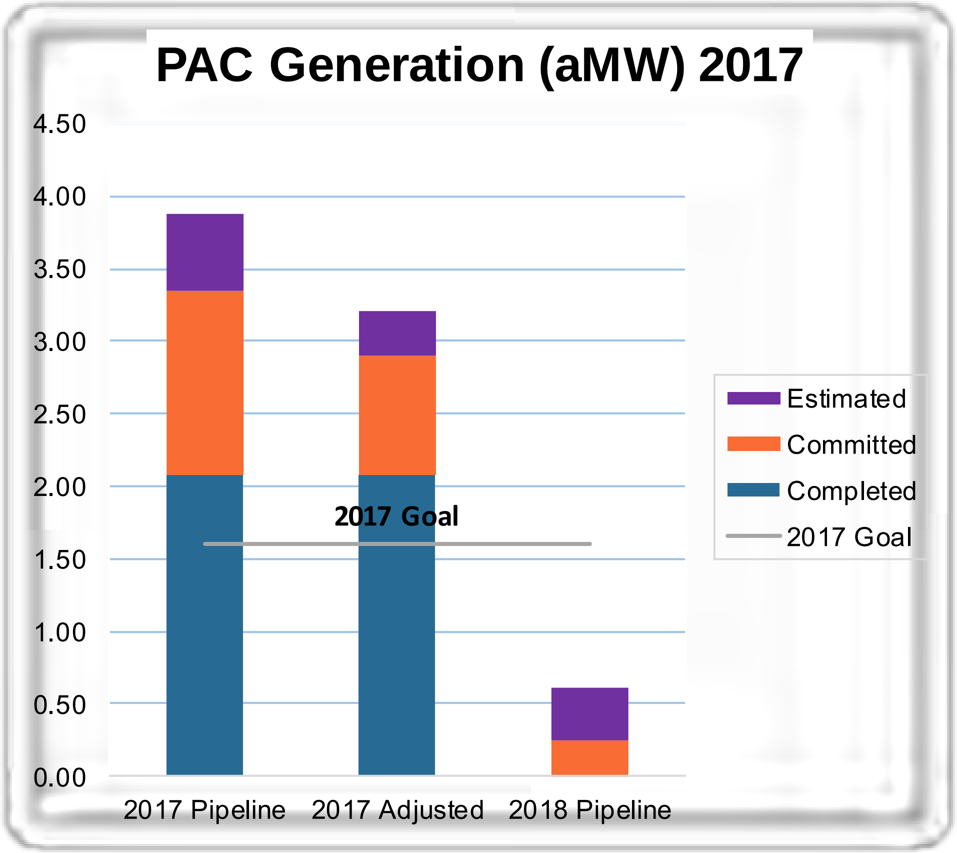
PGE

Forecast achieving 98%

Pacific Power

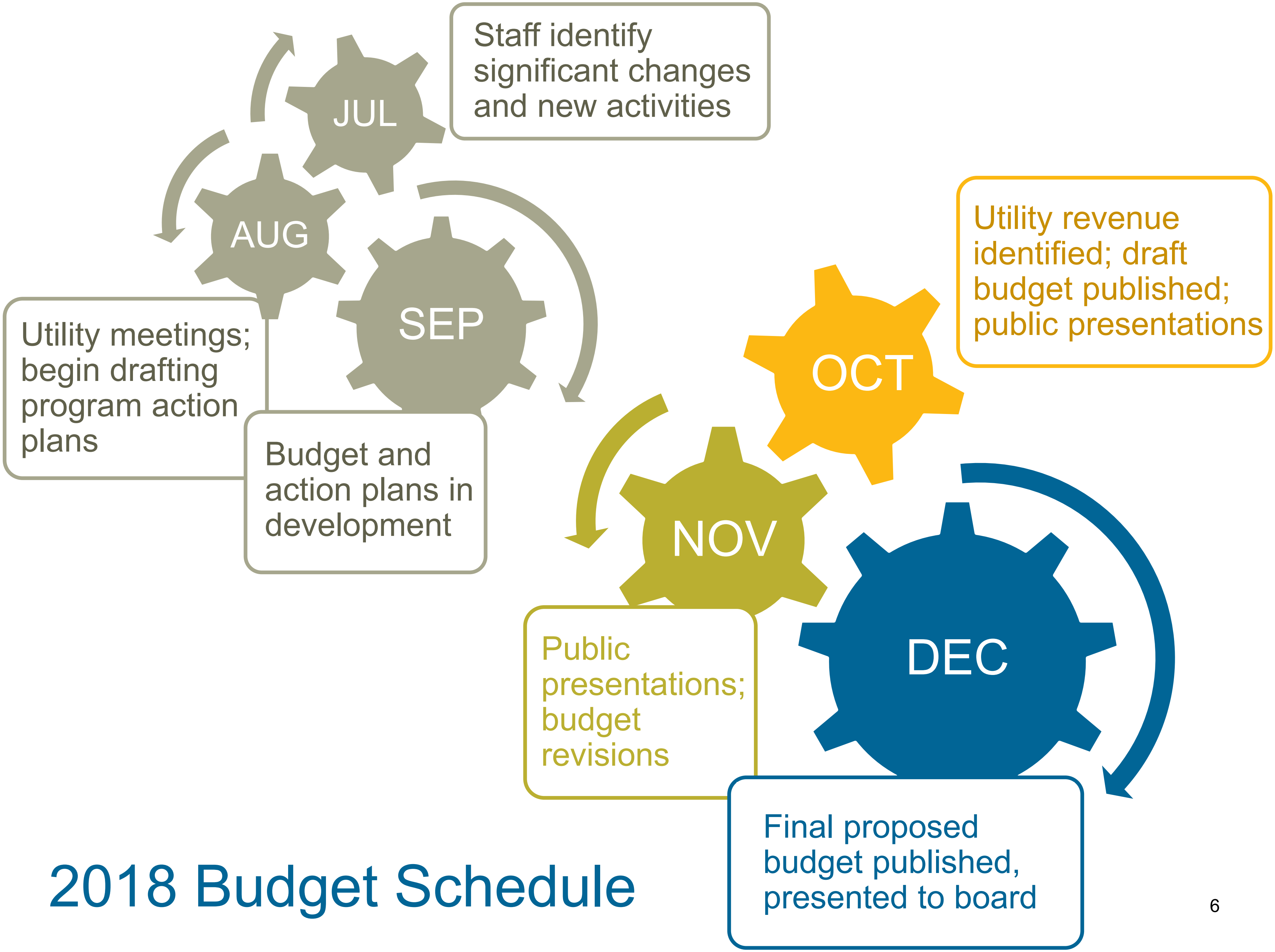
Forecast achieving 197%





[DIVIDER SLIDE] Budget & Action Plan Building Blocks

Budget & Action Plan Building Blocks



2018 Budget Schedule

Building Blocks for Budget and Action Plan

1

2015-2019 Strategic Plan goals and strategies

2

Utility Integrated Resource Plans

Renewable resource availability

3

Market knowledge and context

4

Areas of emphasis

Based on goals, strategies and context

2015-2019 Strategic Plan Goals

240 aMW — Electric efficiency goal

24 MMTh — Natural gas efficiency goal

10 aMW — Renewable generation goal

Optimize internal operations & management

2015-2019 Strategic Plan Strategies

Expand participation

Flexibly support mature renewable technologies

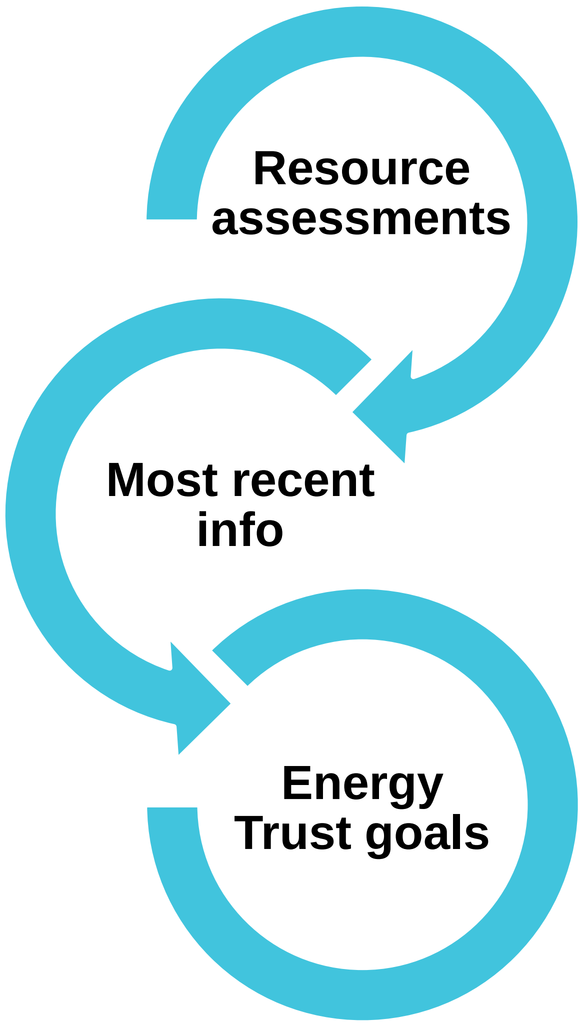
New approaches, emerging technology

Pursue complementary initiatives with others

Strengthen operational effectiveness

Manage transitions

Annual Goal Setting

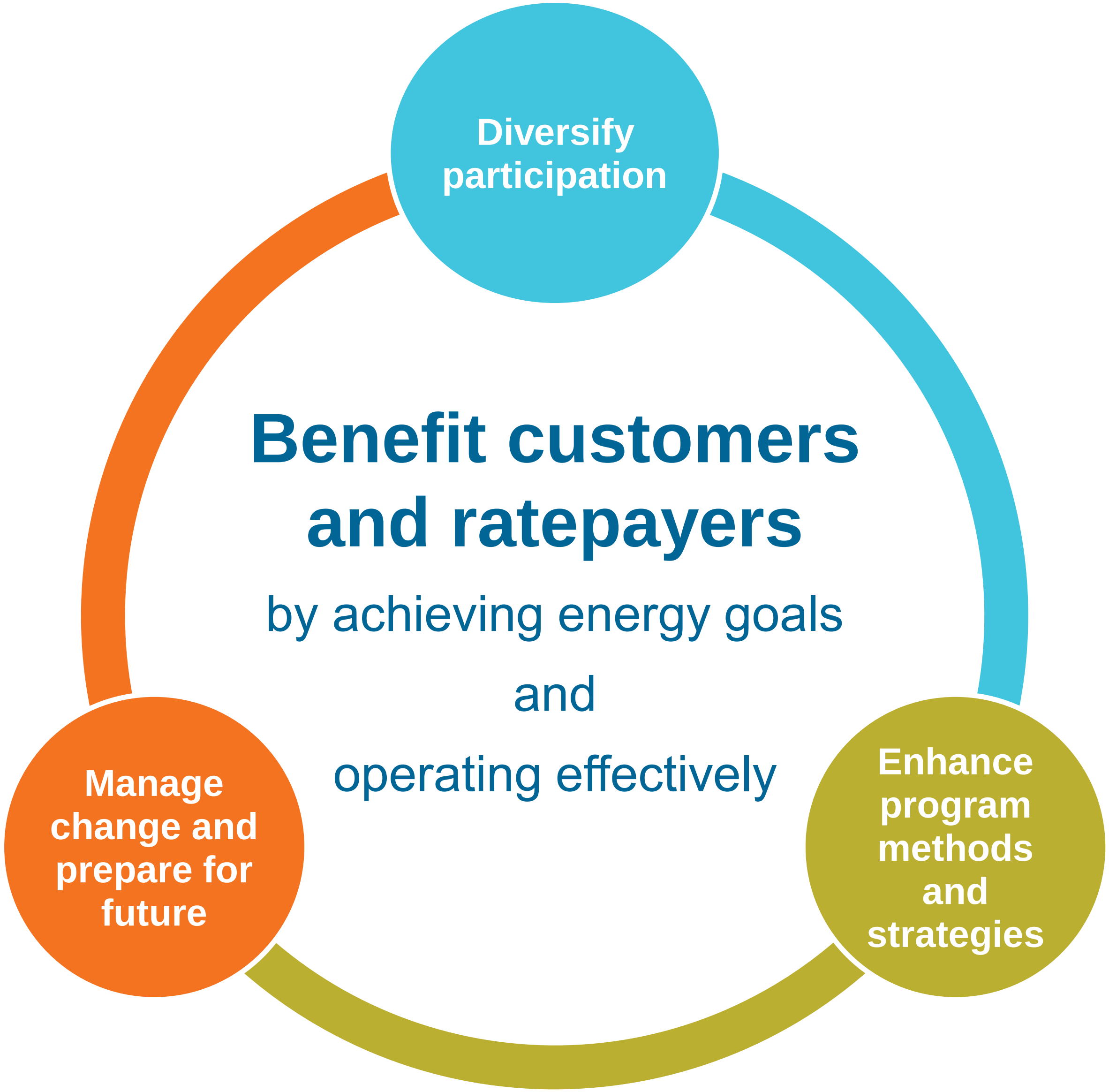


- Annual savings goals approximate each utility's Integrated Resource Plan (IRP) target
  - Staggered two-year IRP cycles
  - Energy Trust annual goals can be higher because of new information
  - Utilities file tariffs to collect funding necessary to meet annual goal
- Generation goals informed by resource availability and market drivers

Market Knowledge and Context

- 4th year of strategic plan
- Stable economy driving high activity in some program areas
- Oregon population diversifying, stakeholder interest growing
- Changing policies, markets and technologies
- Lower savings per project
- Avoided cost shifts
- Cost-effectiveness challenges

Draft 2018 Areas of Emphasis



[DIVIDER SLIDE] Draft 2018-2019 Action Plan Highlights

Draft 2018-2019
Action Plan Highlights

Diversify Participation

- Increase outreach to small/medium businesses and agriculture
- Identify and prioritize strategies to increase access to solar in low-income communities
- Contract with community-based organizations to reach under-served communities
- Apply diversity, equity and inclusion lens to our internal operations and how we deliver programs

Enhance Program Methods and Strategies

- Utilize new, improved data resources in analysis and targeted marketing
- Leverage energy-related initiatives spearheaded by others
- Foster long-term relationships with business customers and support long-term project planning for communities
- Focus outreach to irrigation hydropower and biogas projects

Manage Change and Prepare for Future

- Support targeted demand-side management efforts with utilities
- Collaborate with NEEA to identify new measures and strategies
- Implement transitional strategies for key program areas (ex. solar, lighting)
- Implement recommendations from internal Organizational Review and Budget Review Projects

[DIVIDER SLIDE] Draft 2018 Annua Budget

Draft 2018 Budget

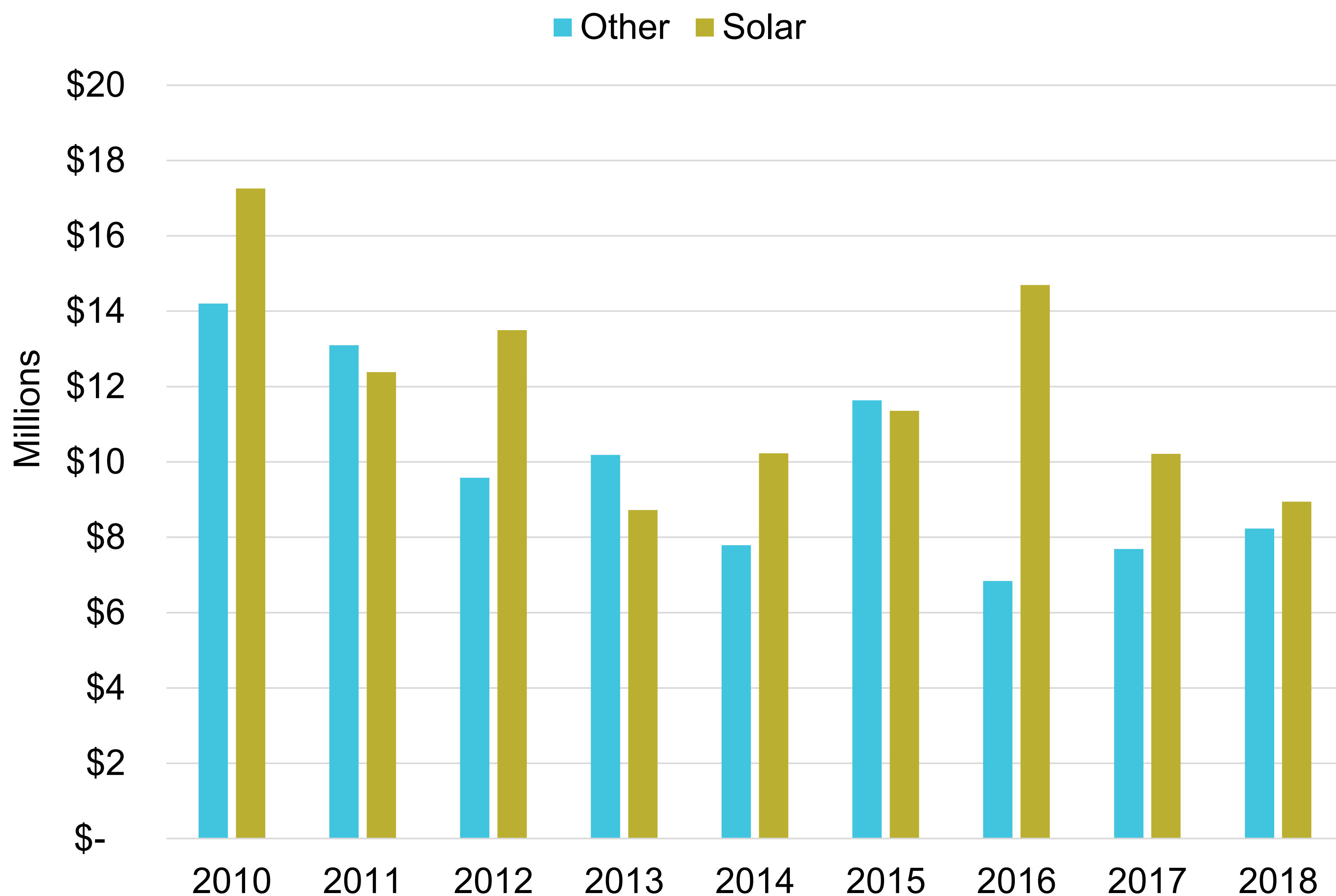
2018 Renewable Energy Programs

How we budget: “Activity” vs “Profit & Loss” (P&L)

- Activity: What we plan to do with new or rolled-over funding in a given year (dedications).
  - Analogy: ‘Engagement Budget’

- P&L: Actual spending projected to occur in a given year. Includes funds dedicated from current and previous year’s Activity Budgets.
  - Analogy: “Wedding Day Budget”

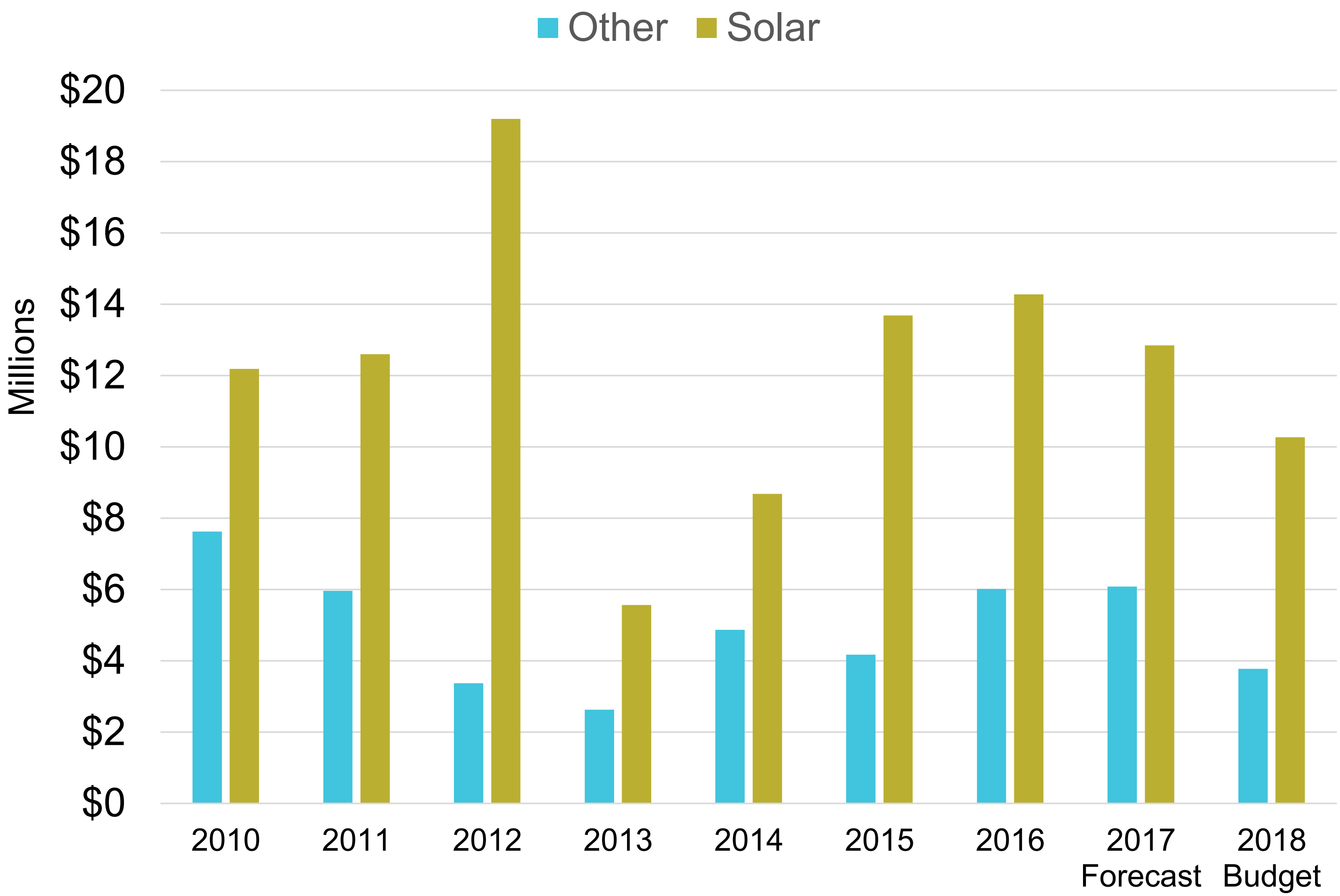
Renewable Energy Activity Budget Trends



2018 Renewable Energy Activity Budgets

	Total Costs: $ Million			
	PGE	Pacific Power	Total	%
Other Renewables	$5.85	$3.26	$9.11	50.4%
Solar	$5.53	$3.42	$8.95	49.6%

Renewable Energy P&L Trends



2018 Renewable Energy Programs

	Total Budget 2017		Total Budget 2018		*% Change*	
	$ Million	aMW	$ Million	aMW	*$*	*aMW*
Other Renewables	$6.42	0.001	$3.91*	0.00	*-39%*	*N/A*
Solar	$13.41	2.86	$10.23	2.18	*-24%*	*-24%*
Total	**$19.83**	**2.86**	**$14.15**	**2.18**	*-29%*	*-24%*

Solar down 24%

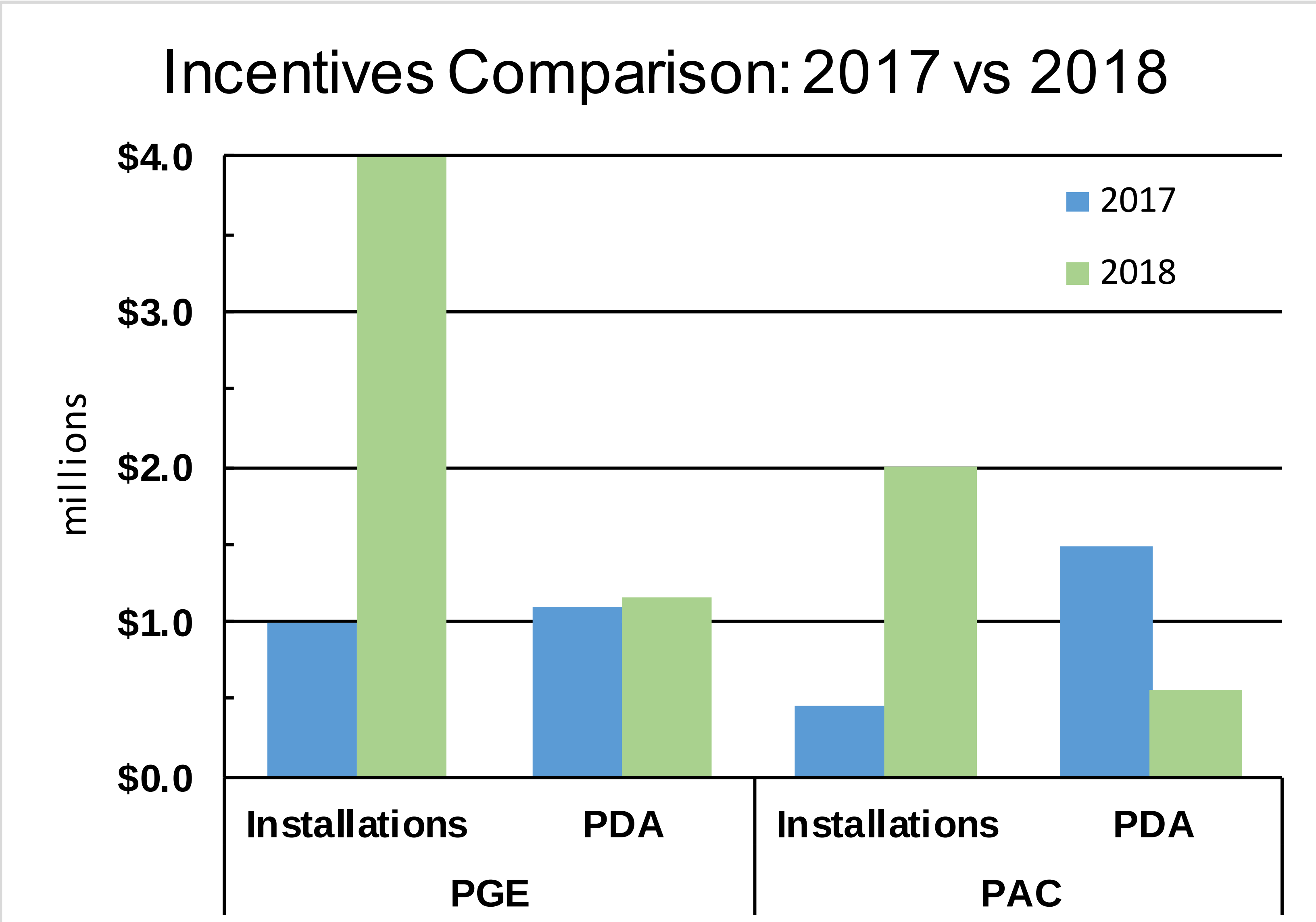
$14.15 million in customer incentives, services and delivery

* Other Renewables expenditures include:
- Project development assistance payments for potential generation in future years (63%)
- Staff, professional services, outreach and other allocated costs (37%)

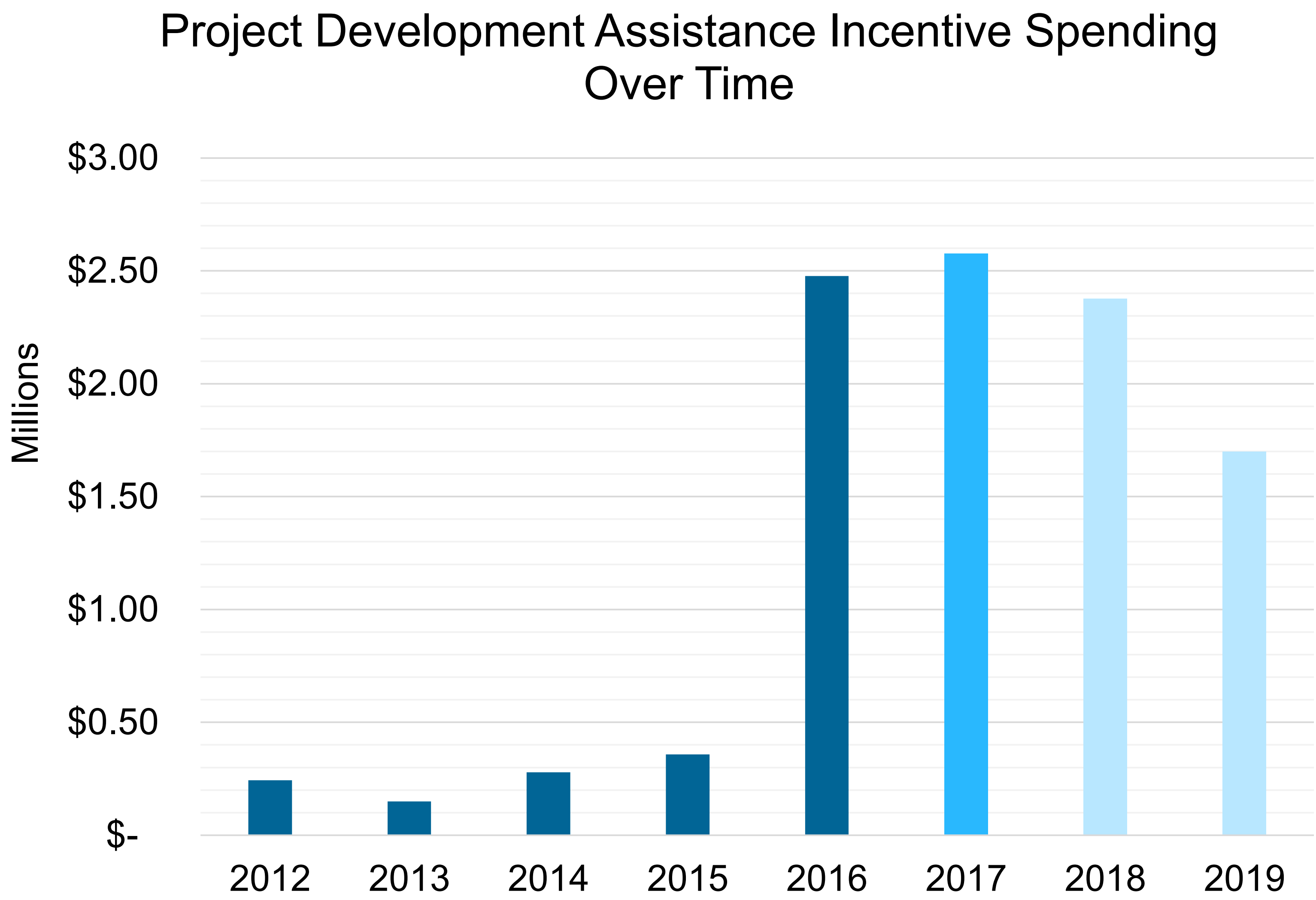
Other Renewables Incentives Activity Budget

	Incentives Only, $ Million			
	PGE	Pacific Power	Total	%
Installation Incentives	$ 4.00	$ 2.00	$ 6.00	78%
Project Development Assistance (PDA)	$ 1.16	$ 0.56	$ 1.72	22%
Total	$ 5.16	$ 2.56	$ 7.72	100%

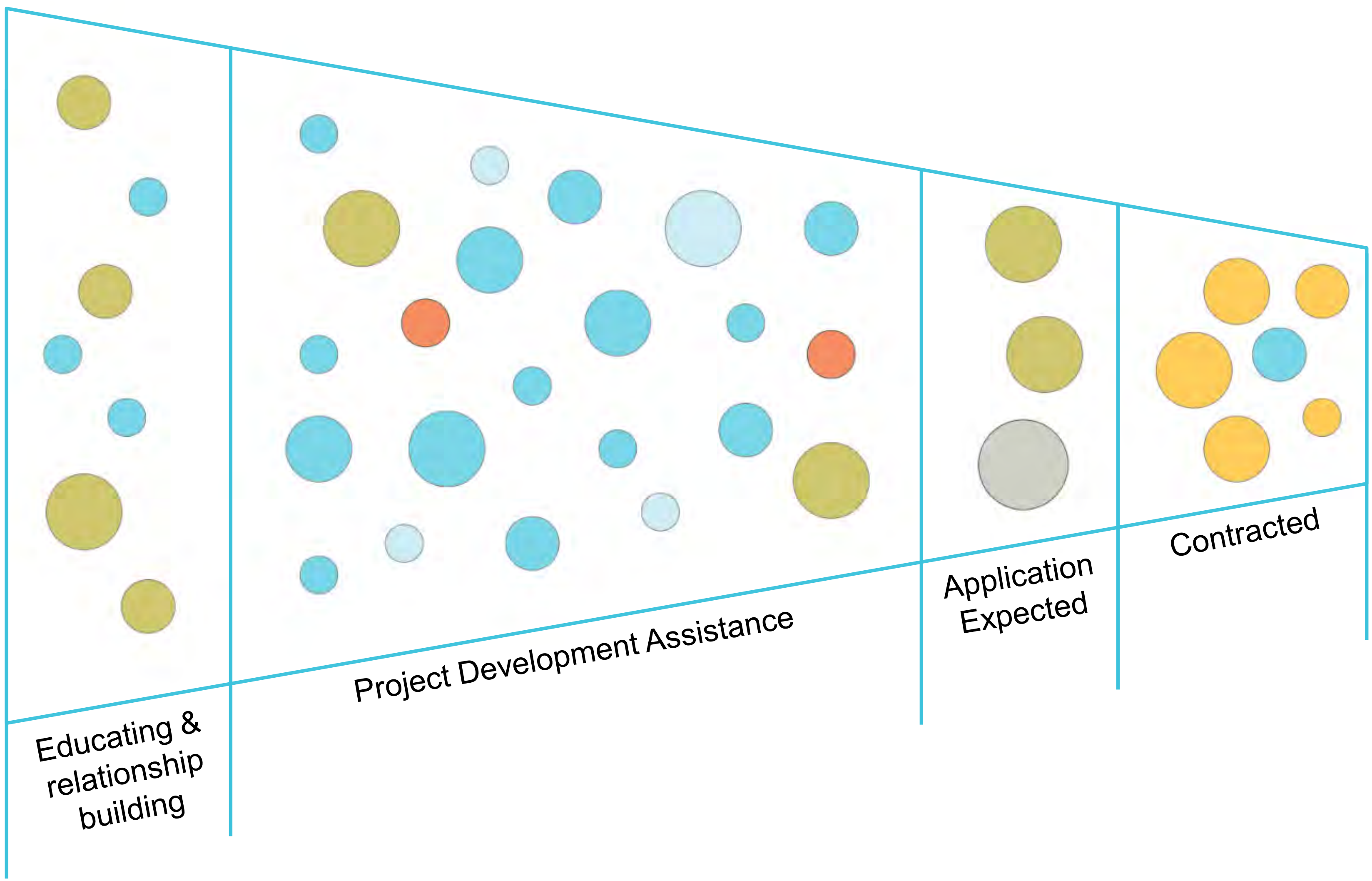
Other Renewables Incentives Activity Budget



Other Renewables PDA Trends (P&L)



Pipeline Building Process (representative)



Current Project Development Assistance Pipeline

Project Type	Project Count
Biogas (brewery)	2
Biogas (wastewater)	2
Biomass	1
Community wind (municipal)	1
Geothermal	2
Irrigation Modernization	20
Other Irrigation Hydro	21
Other Non-Irrigation Hydro	3
Total	**52**

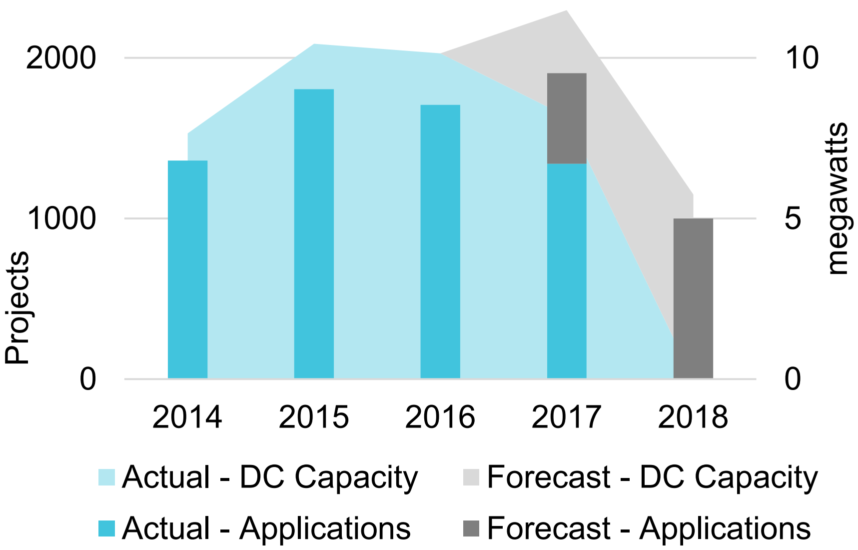
Activity Budget: Solar Incentives

	Incentives Only, $ Million			
	PGE	Pacific Power	Total	%
Residential Solar	$1.80	$0.90	$2.70	44%
Business Solar	$1.80	$0.90	$2.70	44%
Solar Ready, PDA & Incentive Adders	$0.42	$0.25	$0.67	11%
Total	$4.02	$2.05	$6.07	100%

Activity Budget: Solar Forecast

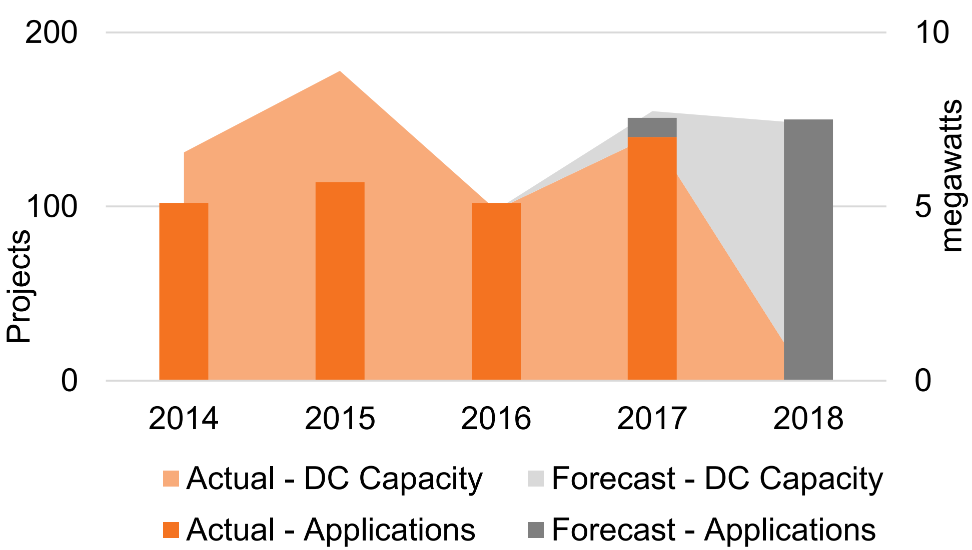
Residential

Approximately:
- 1,000 projects
- 6 MW capacity
- About $0.60/W incentive
- ~50% reduction in volume



Business

Approximately:
- 150 projects
- 7 MW capacity
- About $0.45/W incentive
- Similar volume



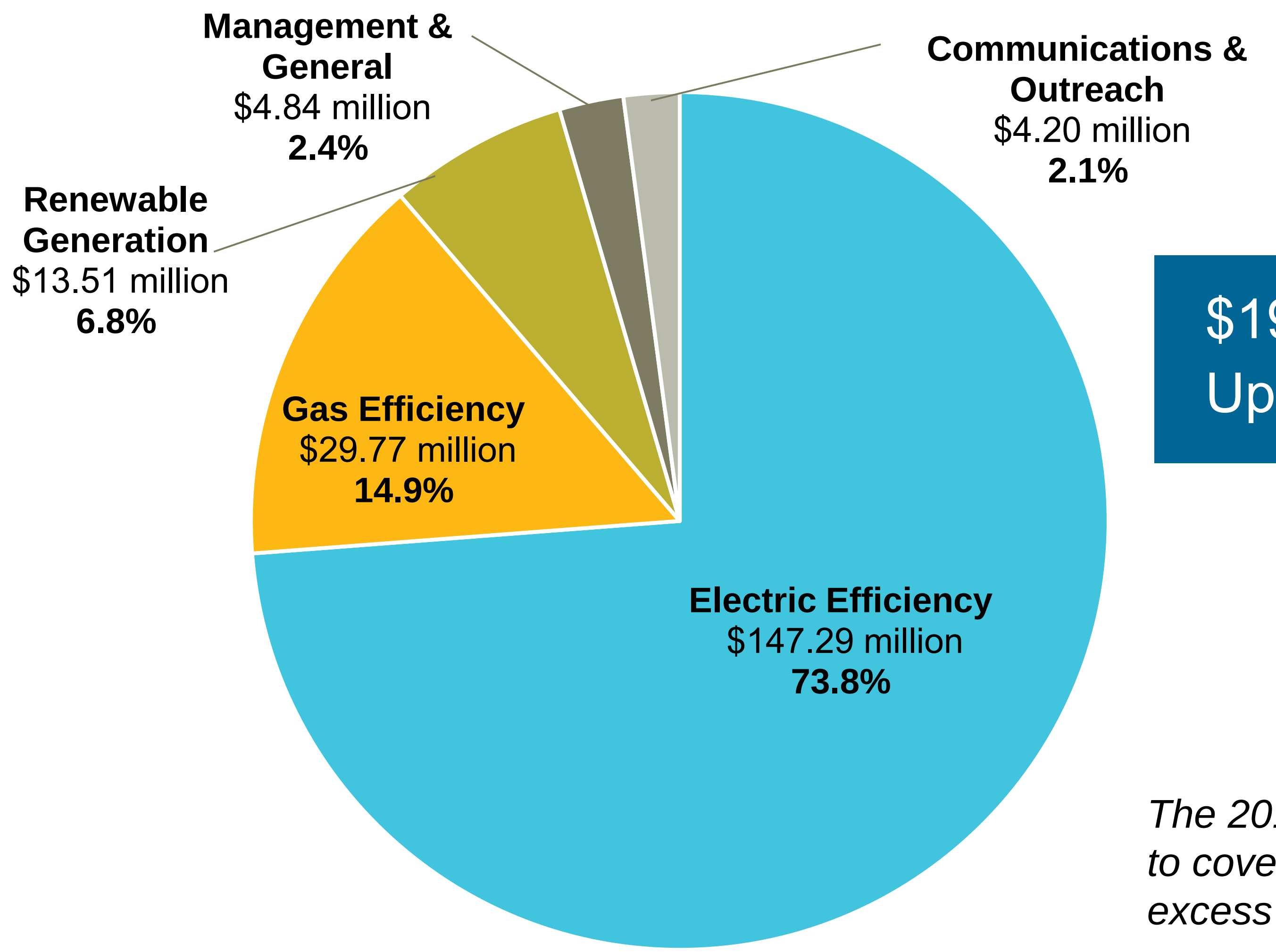
2018 Draft Budget Summary

- Investing $199.6 million
- Saving 56.52 aMW and 6.88 MMTh
  - Electric savings up by 0.2%
  - Gas savings down by 7.2%
- Delivering highly cost-effective energy
  - 3.0 cents/kWh levelized
  - 33.5 cents/therm levelized
- Generating 2.18 aMW
  - Renewable generation down 23.8%, largely due to solar state tax credit expiration and tighter budgets

2018 Draft Budget Summary

- Overall spending up 0.5% due to increased project volume and an increase in internal costs
- Incentives are 55.7% of total planned expenditures
- Revenue down slightly; reserves remain within targets
- Low administrative and program support costs at 6.7%
- Three-year rolling staffing costs are at 7.1%, below OPUC performance measure

2018 Draft Budget Expenditures

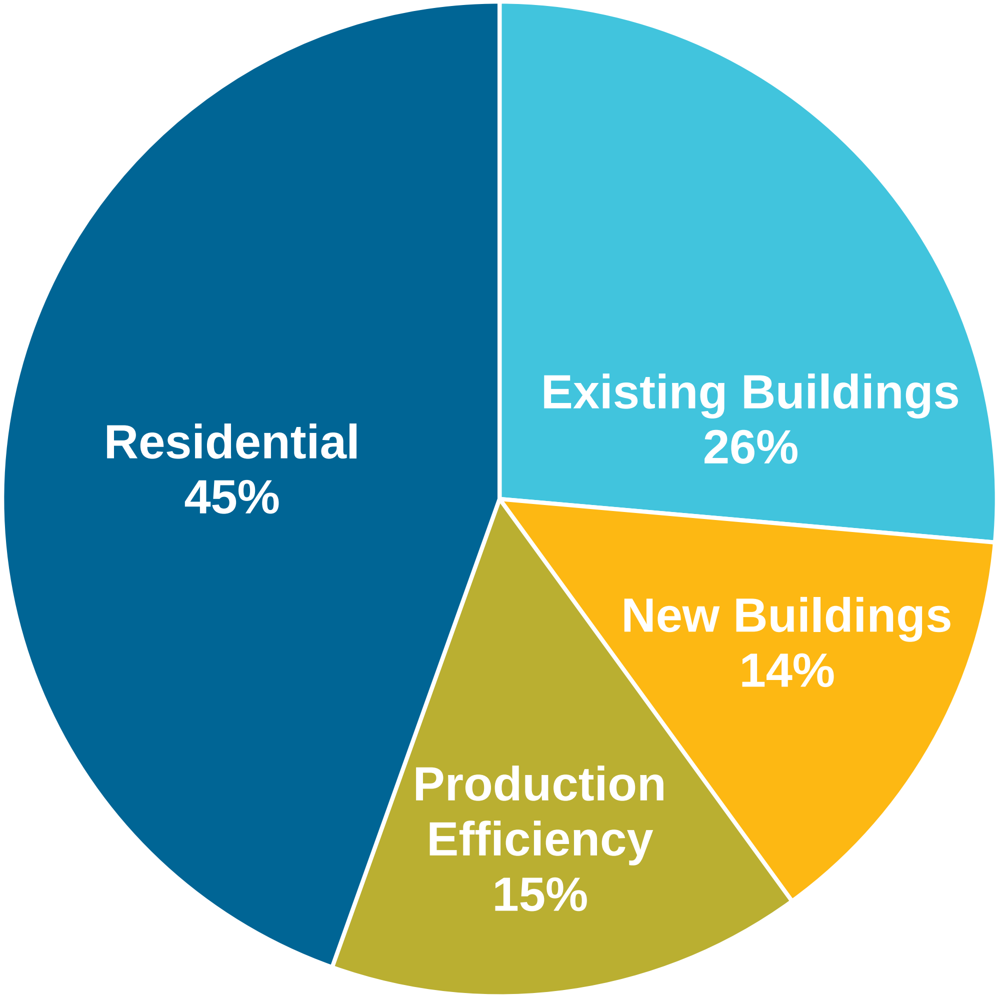


$199.6 million

Up 0.5% from 2017

The 2018 budget utilizes reserves to cover planned expenses in excess of anticipated revenue.

2018 Natural Gas Savings by Program

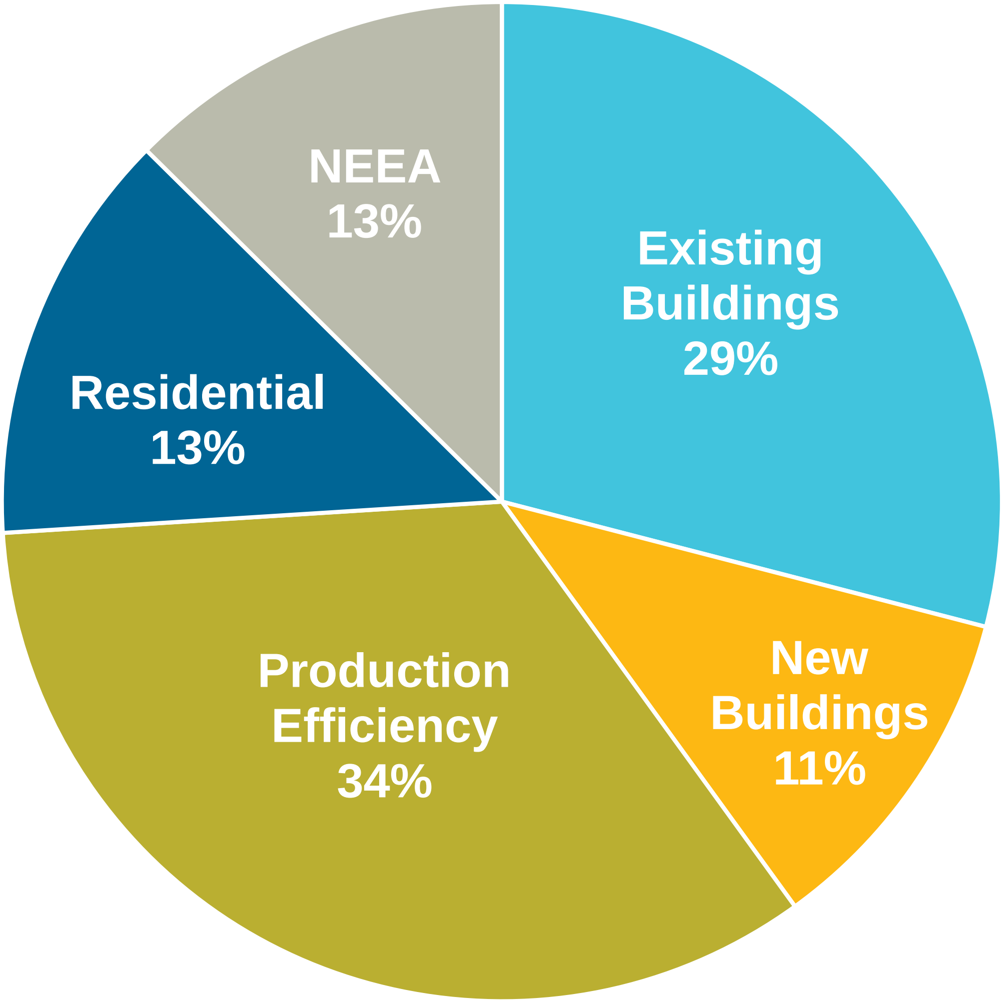


6.88 MMTh goal
33.5 cents/therm

- Down 7.2% from 2017
- $31.2 million in total costs, including customer incentives, services and delivery

MMTh: million annual therms
Cost per therm is levelized

2018 Electric Savings by Program



56.52 aMW goal
3.0 cents/kWh

- Up 0.2% from 2017
- $154.3 million in total costs, including customer incentives, services and delivery

aMW: average megawatts
Cost per kilowatt hour is levelized

NEEA Goals and Budget

	2017 Goal	2017 Forecast	2018 Goal	2018 Budget ($ Million)	2018 Levelized Cost (per kWh)
PGE (aMW)	4.12	4.57	4.51	$4.48	1.3¢
Pacific Power (aMW)	2.87	3.17	2.65	$2.63	1.3¢
NW Natural	-	-	-	$1.25	N/A
Cascade Natural Gas	-	-	-	$0.14	N/A

- Energy Trust allocated budget to NEEA for gas market transformation activities; savings are expected in subsequent years
- Unlike the other gas utilities, Avista pays for its share of NEEA gas market transformation activities directly

2018 Utility Savings & Generation Summary

	2017 Budget Savings & Generation (Net) aMW or MMTh	2018 Budget Savings & Generation (Net) aMW or MMTh	IRP Target* for 2018 (Net) aMW or MMTh	2018 Budget ($ Million)	2018 Budget Levelized Cost per kWh or therm
PGE (Efficiency)	34.97	37.03	32.39	$97.69	2.9¢
Pacific Power (Efficiency)	21.43	19.49	19.76	$56.59	3.2¢
NW Natural (OR)	6.25	5.62	4.44	$24.82	32.6¢
NW Natural (WA)	0.28	0.36	0.36	$2.39	52.1¢
Cascade Natural Gas	0.56	0.55	0.53	$2.85	38.3¢
Avista	0.32	0.35	0.35	$1.12	21.7¢
PGE (Renewable)	1.23	1.08	N/A	$7.25	N/A
Pacific Power (Renewable)	1.63	1.10	N/A	$6.90	N/A

MMTh: million annual therms
aMW: average megawatts

Net savings

** IRP targets reflected in net savings using 2018 Energy Trust net-to-gross ratios. These net targets align with the energy efficiency potential incorporated in current utility IRP filings.*

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[DIVIDER SLIDE] Summary

Summary

Customer Benefits from 2018 Investments

- **$707 million in future bill savings** from energy improvements made in 2018 with help from Energy Trust
- Improved air quality by avoiding 4.4 million tons of carbon dioxide
- Enough energy to power 45,820 homes and heat 12,800 homes
- Continued high customer satisfaction
- Expanded access and participation statewide
- Training and support for 2,400 local businesses

Budget Outreach Schedule

October & November	December
RAC/CAC presentations, Oct. 25 Draft budget online, Nov. 1 Recorded webinar online, Nov. 7 Board of Directors, Nov. 8 OPUC public meeting, Nov. 16 RAC/CAC updates, Nov. 17 **Public comments due Nov. 17** Comments reviewed, final adjustments	Final proposed budget online, **Dec. 8** Board of Directors, **Dec. 15,** Action on Final Proposed 2018-19 Budget and Action Plan

+ **www.energytrust.org/about/budget**

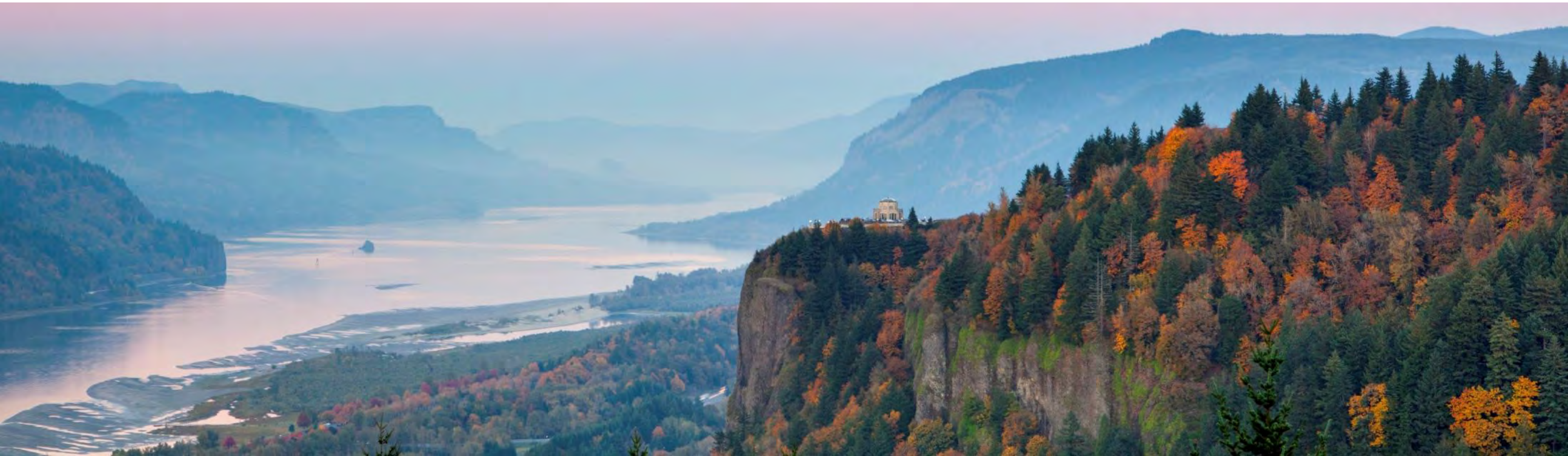
Send comments to info@energytrust.org

Discussion and Feedback

- What questions do you have?
- What information needs clarification?
- Other feedback?

+ www.energytrust.org/about/budget
Send comments to info@energytrust.org

+ Comments due November 17



Thank You

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Energy Trust of Oregon

[DIVIDER SLIDE] Supplemental Information

Supplemental Information

Projected 2017 Results by Utility

	2017 Budget Savings & Generation (Net) aMW or MMTh	2017 Budget Levelized Cost per kWh or therm	2017 Forecast Savings (Net) aMW or MMTh	Forecasted % of 2017 Savings Goal (Net)	Forecasted 2017 Levelized Cost per kWh or therm
PGE (Efficiency)	34.97	2.9¢	41.51	119%	2.5¢
Pacific Power (Efficiency)	21.43	2.9¢	22.85	107%	2.5¢
NW Natural (OR)	6.25	32.9¢	5.45	87%	29.8¢
NW Natural (WA)	0.28	55.9¢	0.35	125%	49.1¢
Cascade Natural Gas	0.56	37.7¢	0.51	90%	29.2¢
Avista	0.32	22.7¢	0.34	108%	24.2¢
PGE (Renewable)	1.23		1.20	98%	
Pacific Power (Renewable)	1.63		3.21	197%	

MMTh: million annual therms
aMW: average megawatts

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Net savings

Utility Detail: Renewable Energy

PGE: 2018 Renewable Energy Generation, Budget by Program (P&L)

	2017 Generation Goal aMW	2017 Generation Forecast aMW	2018 Generation Goal aMW	2018 Budget ($ Million)
Other Renewables (0%*)	-	-	-	$1.93
Solar (100%*)	1.2	1.2	1.1	$5.32
TOTAL	**1.2**	**1.2**	**1.1**	**$7.25**

* % of total 2018 generation

Pacific Power: 2018 Renewable Energy, Budget by Program (P&L)

	2017 Budget Generation in aMW	2017 Generation Forecast aMW	2018 Budget Generation in aMW	2018 Renewables Cost ($ Millions)
Other Renewables (0%)	0.001	0.0016	-	$1.99
Solar (100%*)	1.6	3.2	1.1	$4.91
TOTAL	**1.6**	**3.2**	**1.1**	**$6.90**

* % of total 2017 generation