

SB 1547 Community Solar

2019 Program Implementation Update

December 2018



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Executive Summary

In 2016, the Oregon Legislature enacted Senate Bill (SB) 1547, which requires the Oregon Public Utility Commission (Commission) to establish a program for the procurement of electricity from community solar projects. Community solar projects provide electric company customers the opportunity to share in the costs and benefits associated with the electricity generated by solar photovoltaic systems, as owners of or subscribers to a portion of the solar project. Establishing a Community Solar Program (CSP) for Oregon is a major milestone in expanding access to solar technologies. In addition, this program's structure, size, and objectives represent a level of complexity above and beyond what the Commission and its stakeholder have undertaken in implementing a voluntary renewable energy program. Since 2016, the Commission has taken steps to conduct an inclusive implementation process and carefully design and execute a program that will operate successfully, expand opportunities, and have a fair and positive impact across electric company ratepayers.

Section 28 of SB 1547 requires the Commission to report to the Legislative Assembly on the implementation of the community solar program (Section 22) on or before January 1, 2019. As part of the report, the Commission may make recommendations for the Legislature. This report summarizes the status of implementing Section 22 of SB 1547 and covers three phases of implementation: rulemaking, key Commission decisions, and program implementation.

Rulemaking

After an inclusive stakeholder process, the Commission adopted formal rules for the CSP on June 29, 2017, through Order No. 17-232, which adopted Division 88 of Chapter 860 of the Oregon Administrative Rules. The rules provide for a series of extensive implementation actions that must be accomplished before the formal launch of the CSP, including procurement of third-party program administrator and low-income facilitator services and development of the program implementation manual that will provide detailed, technical guidelines for implementation of the CSP. The rules also define the program size, community solar project requirements, program participant requirements, and details surrounding the opportunity for low-income participants, as well as information regarding on-bill crediting.

Key Commission Decisions

Concurrent with the program implementation activities, the Commission has taken additional steps to move key decisions forward. Thus far, the Commission has set the CSP bill credit rate at the volumetric residential retail rate, on an interim basis, to allow for a successful and timely launch of the CSP, and will work with the program administrator to implement the interim alternative bill credit rate upon CSP launch. The Commission has also taken a critical step in facilitating the recovery of program start-up costs with the approval of electric utilities' applications for deferred accounting to recover CSP start-up costs. The Commission will work with the utilities to ensure appropriate tariffs are in place to begin collecting these funds once other aspects of the program are finalized.

Program Implementation

In September 2017, the Commission moved CSP implementation from the rulemaking phase to the program implementation phase with the support of a wide network of stakeholders. The ultimate goal of this phase is to complete program design and launch the program for customer participation. The program implementation phase has focused on two major work streams to date:

1. Competitive procurement of program administration and low-income facilitator services; and
2. Efforts to scope and examine major implementation issues in coordination with stakeholders.

A major milestone in program administration will be the execution of a contract for program administrator and low-income facilitator services.

Next Steps

Program implementation and launch will intensify when the contract for the third-party program administrator has been approved by the Commission. Commission Staff and the program administrator will engage with stakeholders during the program implementation manual development for a transparent and inclusive process to ensure effective program launch. Robust development will take place from the date of contract execution, with program launch anticipated in 2019.

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Introduction and Background

The Legislature passed Senate Bill (SB) 1547 in 2016, with Section 22 requiring the Oregon Public Utility Commission (Commission or OPUC) to establish by rule a program for the procurement of electricity from community solar projects. SB 1547 defines a community solar project as one or more solar photovoltaic energy systems that provides the opportunity for electric company customers to share in the costs and benefits associated with the electricity generated by those systems. SB 1547 Section 28 also requires the Commission to report on the implementation of the community solar program (CSP) to the Legislative Assembly by Jan. 1, 2019. As part of this report, the Commission may make any recommendations for legislation.

The CSP creates an opportunity for electric company customers to own or subscribe to a portion of a solar project. Owners and subscribers (“participants”) pay a fee to the “project manager” which covers the cost to construct and operate the solar project. The solar project provides electricity directly to the electric company to serve all customers, and participants receive a credit on their electric bill for the amount of electricity generated by their portion of the solar project. SB 1547 requires the bill credit to reflect the resource value of solar (RVOS) and allows the Commission to adopt an alternate bill credit rate for good cause.

SB 1547 also mandates that the Commission adopt rules prescribing what qualifies a project to participate in the program, certify qualified projects for participation, prescribe the form and manner by which project managers may apply for certification under the program, and require electric companies to enter into a 20-year power purchase agreement with a certified project. Project managers can be utility companies or third-parties. The legislation further directs that in adopting rules for project qualification, the Commission should consider ways to incentivize participation, minimize cost shifting, protect participants from undue financial hardship (where an electric company is the project manager), and protect the public interest. The legislation also requires the determination of a methodology by which 10 percent of the total generating capacity of the projects operated under the program will be made available for use by low-income residential customers.

Rulemaking and Program Framework

The first phase of Commission’s implementation of SB 1547, Section 22 was to establish administrative rules which provide a framework for designing and launching the CSP. Beginning in July 2016, Commission Staff sought an inclusive process in order to incorporate as much stakeholder collaboration as possible.

Process

OPUC launched its public process to establish administrative rules for the CSP in August 2016. Over the course of seven months, the Commission held five topic-specific workshops through February 2017. During this time, the Commission also held a number of one-on-one meetings with key stakeholders, such as the electric utilities, equity and environmental justice community, and solar industry, enabling additional opportunity to explore certain program elements further. In January 2017, Commission Staff coordinated a public meeting where stakeholders had their first opportunity to provide public comments directly to the Commissioners.

A version of draft rules were released to stakeholders on May 1, 2017. Stakeholders had an opportunity to comment on the draft CSP rules at a May 22, 2017, rulemaking hearing.¹ Additionally, members of Commission Staff traveled with the Energy Trust of Oregon along with other organizations to receive comments and concerns, as well as answer any questions directly from members of communities around the state.

OPUC appreciates the ample stakeholder and community feedback received throughout this process. The Commission adopted formal rules for the CSP on June 29, 2017, through Order No. 17-232, meeting the statutory deadline to adopt rules by July 1, 2017. The order adopted Division 88 of Chapter 860 of the Oregon Administrative Rules, which provide for a series of extensive implementation actions that must be accomplished before the formal launch of a community solar program. The content of the program rules are outlined in the following Program Details section.

Program Details

Program Administration

The Commission has used a competitive bidding process to select a third-party program administrator (PA).² One of the first actions of the PA will be to jointly develop with the Commission a program implementation manual through a public process. This manual will serve as the technical guidelines and requirements for implementing the CSP. As a contractor serving the Commission, the PA will develop and manage aspects of the program including budget, data management, project pre-certification and certification, and other duties as assigned by the Commission. A low-income facilitator (LIF) will also be contracted to serve as a liaison to assist the program in meeting the low-income capacity requirements. The LIF will also develop guidelines for engaging low-income customers and best practices for data security and privacy.

Program Size

Pursuant to the rules adopted by the Commission, an initial program capacity tier of 160 megawatts (MW) was adopted. This capacity tier was based on two and a half percent of each electric company's 2016 system peak. This initial tier was set in an effort to launch the program at a size large enough to sustain the initial administrative costs, while ensuring the opportunity to adjust any aspect of the program before further expansion.³

Table 1. Program Capacity Allocated by Utility (MW)

	Initial Program Capacity Tier
Portland General Electric	92.6
PacifiCorp	64.2
Idaho Power Company	3.3
Total	160.0

¹ A comprehensive timeline of the community solar rulemaking process and stakeholder comments can be found on the Commission's e-Docket system under AR 603. It can also be accessed here:

<https://apps.puc.state.or.us/edockets/docket.asp?DocketID=20304>

² As discussed in further detail later, utilizing the services of the Department of Administrative Services, the Commission is midway through procurement procedures to finalize the contract with the third-party administrator.

³ Order No. 17-232.

Project Requirements

Projects must be located within Oregon to participate in the program and customers may participate in projects located anywhere within its electric company's service territory.⁴ At least 50 percent of the nameplate capacity of each project must be reserved for residential and small commercial customers. Projects receive certification from the Commission through a three-step certification phase:

- Register as a PA-approved project manager and comply with the standard of conduct as established by the Commission.
- Receive pre-certification when the project design demonstrates compliance with all CSP requirements. At pre-certification, a project reserves capacity within the capacity tier and is assigned a bill credit rate. Project managers cannot execute contracts with participants until pre-certification is secured.
- Receive final certification when the project is complete and demonstrates compliance with all CSP requirements, including low-income participation requirements and a minimum of 50 percent of project capacity subscribed. Projects can become operational and participants can begin to receive bill credits upon certification.

Participant Requirements

A participant and its affiliates may subscribe up to a total of four megawatts across multiple projects. The term "affiliates" will be further defined in the program implementation manual, which is still to be developed once the third-party program administrator contract has been finalized.

Low-Income Opportunity

SB 1547 required the Commission to determine a methodology by which 10 percent of the total generating capacity of the projects operated under the program would be made available for use by low-income residential customers. The Commission's adopted rules required that at least five percent of each project's capacity and at least five percent of the total program capacity be allocated to these low-income customers.

Billing

The rules determined that costs and benefits of participation in a CSP would be managed through the utility bill. A participant's electric utility will collect the subscription or ownership payments on behalf of project managers, as well as provide the bill credit in an effort to streamline administrative costs and ensure a simplified customer experience. The rules require each electric utility to work with the PA to develop and obtain Commission approval of an on-bill payment model that is flexible enough to allow for multiple ownership and subscription configurations to collect project fees owed by participants.

Other

The rules also describe a number of other important implementation tasks that must be completed before the community solar program can launch, including:

- Completing a program implementation manual in collaboration with the PA and stakeholders;
- Finalizing project manager resources (e.g., project manager registration and project certification requirements and process; project manager training resources; participant enrollment and management platforms);

⁴ Participants may subscribe to a project at a level that does not exceed their average annual consumption of electricity, and a single participant's share in a given project may not exceed 40 percent interest.

- Developing software and systems to support the secure and accurate exchange of large amounts of data and funds between multiple parties;
- Developing consumer resources; and
- Creating cost-recovery mechanisms for program administration and participant bill credits.

Following the adoption of the rules, the Commission ordered Commission Staff to proceed toward launching the program, beginning with contracting the PA and LIF services, and moving forward with key implementation and program design issues while waiting for contract execution.

Key Commission Decisions

Concurrent with the program implementation activities described in subsequent sections, the Commission has taken additional steps to move the program forward in preparation for the hiring of a PA. These additional implementation steps include developing an interim bill credit rate, establishing a mechanism for utility cost recovery, and continuing work on the resource value of solar energy.

Interim Bill Credit Rate

SB 1547 requires that CSP participants receive a bill credit rate that reflects the resource value of solar energy (RVOS), and allows the Commission to adopt a different bill credit rate for good cause. On March 5, 2018, the Commission determined that there is good cause to adopt an alternative bill credit rate due to concerns about the timing and value of RVOS.⁵ On April 24, 2018, the Commission set the CSP bill credit rate at the volumetric residential retail rate, on an interim basis, to allow for a successful and timely launch of the CSP.^{6,7} The Commission adopted the interim alternative bill credit for the initial 25 percent of the program capacity tier (roughly 40 megawatts statewide). Additionally, 25 percent of the initial capacity subject to the interim alternative bill credit rate is reserved for small projects up to 360 kilowatts in size. The Commission will work with the PA to implement the interim alternative bill credit rate upon CSP launch.

In adopting the interim bill credit rate the Commission found that the retail rate had been successful in other jurisdictions,⁸ and therefore would likely prove an effective mechanism to encourage customer participation and result in project development.⁹ The Commission balanced the need to stand up a successful program with the need to minimize cost shifting, stating that accessibility "should be achieved at the lowest cost possible to non-participants in order that cost shifting is minimized."¹⁰ The residential retail rate was determined as representing a midpoint in value between accessibility and minimizing cost-shifting relative to the other rates considered.

⁵ Order No. 18-088.

⁶ Order No. 18-177.

⁷ The volumetric residential retail rate represents the cents-per-kilowatt-hour rate that residential electricity customers pay their electric utility.

⁸ State examples include California, Colorado, Massachusetts, Minnesota, and Rhode Island have based their community solar bill credit rate on iterations of the retail rate. See Commission Staff's February 26, 2018 report filed in Docket. No. UM 1930 and comments filed by OSEIA-CCSA, pp. 13 -16, for discussion of other jurisdictions,

⁹ Order No. 18-177.

¹⁰ Order No. 18-088.

Utility Cost Recovery

SB 1547 allows the costs associated with program start-up to be recovered from all electric company ratepayers, while ongoing CSP costs and Project Manager fees are recovered directly from CSP participants. The Commission has taken a critical step in facilitating the recovery of program start-up costs with the approval of Idaho Power Company, Pacific Power, and Portland General Electric's applications for deferred accounting to recover CSP start-up costs.¹¹ When the costs for PA and LIF services are finalized and utility start-up responsibilities are clarified, the Commission will work with utilities to ensure appropriate tariffs are in place to begin collecting these funds.

Resource Value of Solar

The Commission opened a resource value of solar investigation in 2015. The investigation established a two-phase process to first establish the RVOS methodology and second examine values specific to each electric company. The Commission concluded Phase 1 on September 15, 2017,¹² and anticipates a decision on Phase 2 in early 2019. The Commission intends to launch efforts to incorporate the RVOS decision into CSP implementation and design in 2019.

Program Implementation

In September 2017, the Commission moved CSP implementation from the rulemaking phase to the program implementation phase with the support of a wide network of stakeholders. The ultimate goal of this phase is to complete program design and launch the program for customer participation. The program implementation phase has focused on two major work streams to date:

1. Competitive procurement of PA and LIF services; and
2. Efforts to scope and examine major implementation issues in coordination with stakeholders.

Competitive Procurement of PA and LIF Services

The contract for PA and LIF services represents an entirely new size and scope of services for the Commission. While the exact size and scope of this contract is unknown until it is executed, the nature of this procurement required engagement of the Department of Administrative Services (DAS) Procurement Services. Since the third quarter of 2017, the Commission has been working closely with DAS to procure PA and LIF services in compliance with the state's robust procurement policies and protocols. The process and status of these procurement efforts are described below.

Procurement Milestone	Status
Release RFP	Completed April 16, 2018
Bidders conference	Completed April 25, 2018
Close RFP	Completed May 31, 2018
Notice of Competitive Range - Conduct Interviews	Completed August 23, 2018
Issue Notice of Intent to Award Contract	Completed August 24, 2018
Close Protest Period	Completed September 7, 2018

¹¹ See Order Nos. 16-410, 18-478, and 18-477.

¹² See Order No. 17-357.

Contract negotiations	In progress
Execute contract and begin PA and LIF services	Not yet in progress

Acting as the single point of contact on behalf of the Commission, DAS released the Request for Proposal (RFP) for PA services on April 16, 2018.¹³ The RFP closed on May 31, 2018, and DAS received five proposals. The evaluation team scored proposals based on the following criteria outlined in Section 4.10.2 of the RFP:

- Understanding of the timelines and milestones required to implement the program thoroughly and efficiently, including the approach to start-up and ongoing tasks and understanding of anticipated implementation challenges.
- Approach to CSP cost recovery, including the ability to minimize cost shifting to non-participants and prevent participants from undue financial hardship. This included consideration for the clarity of cost elements and designation of start-up versus ongoing costs.
- Demonstrated experience and approach to managing large, complex programs.
- Demonstrated ability to handle substantial monthly transactions between multiple entities including detailed financial settlements and secure customer data. This included consideration of the software and other tools proposed to perform the PA services.
- Approach to facilitating the CSP’s low-income elements, including outreach and LIF management.
- Approach to stakeholder engagement and the resolution of policy questions with multiple stakeholders.
- Demonstrated ability to identify and manage conflict of interest.

On August 24, 2018, DAS issued the Notice of Intent to Award a Contract to Energy Solutions. The procurement process entered the contract negotiation phase and contract negotiations are currently underway. Because this is a new and unique scope of services, the timeline to complete contract negotiations is unknown. While the Commission is taking steps to promote an expedient process, it continues to focus its efforts on several key principles:

- Adhering to the state’s procurement policies and protocols;
- Ensuring the complete and timely delivery of these complex services;
- Transparency of process; and
- Securing the best value for ratepayers.

When contract negotiations are complete, the Commission will notify stakeholders of the process and timeline to complete program design and execute program launch. Further, the PA, LIF, and the Commission will begin the process to engage stakeholders in program implementation manual development and other critical program launch processes.

Efforts to Scope and Examine Major Implementation Issues in Coordination with Stakeholders

There are a number of outstanding implementation tasks that must be completed prior to launching the program. The majority of these tasks will require the active participation of the PA and LIF. However, the Commission has been leading a stakeholder process to identify and address CSP implementation actions that can be taken concurrently with the DAS-led PA and LIF procurement effort.

¹³ See RFP-DASPS-2250-17.

On October 19, 2017, stakeholders and the Commission agreed to form stakeholder-driven topical “Implementation Subgroups” to explore relevant and timely Community Solar implementation issues.¹⁴ The subgroups organized to date include:

- Low Income
- Funding, Data and Financial Exchange, Billing, Tariffs
- Project Details
- Consumer Protection
- RVOS And Bill Credit Determination (suspended following the Commission’s interim alternative bill credit rate decision)

OPUC greatly appreciates the continued efforts of the subgroup leaders and members. The subgroups continue to produce thoughtful discussion and raise important implementation issues. This work will accelerate PA onboarding and materially benefit the speed and quality of the program implementation manual development process.

Next Steps

Based on the status of procurement and additional implementation activities, program launch is anticipated in 2019.

Included here are a number of key milestones for program launch. The following will be integral to program success and full implementation, and will move forward once the PA has been contracted:

- Develop the program implementation manual through a robust stakeholder process.
- Develop and implement a robust and equitable strategy to create meaningful participation opportunities for customers experiencing low incomes.
- Publish a suite of consumer resources, including a program website, a clearinghouse to link users to educational resources and avenues to enroll in a project, as well as branding and marketing materials for effective program outreach.
- Launch Project Manager resources and registration process.
- Launch project pre-certification and certification processes.
- Deploy software and processes that facilitate on-bill payment and crediting along with all required data and funds exchanges.

Once the PA contract has been executed, CSP implementation is expected to move quickly, with the Commission playing a continued role in engaging stakeholders, making key decisions for the finalization of the program implementation manual, and meeting key deliverable due dates to ensure successful program launch in 2019.

¹⁴ See Appendix B for summaries of subgroup activity.

Appendix A

OPUC Staff Memo: Community Solar Implementation Update May 23, 2018

ITEM NO. 2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: May 29, 2018

REGULAR	X	CONSENT	EFFECTIVE DATE	N/A
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DATE: May 23, 2018

TO: Public Utility Commission

FROM: Caroline Moore

THROUGH: Jason Eisdorfer and JP Batmale

SUBJECT: OREGON PUBLIC UTILITY STAFF: (Docket No. UM 1930) Update to Rate Impact Analysis for the Community Solar Program Alternate Interim Bill Credit Rate.

STAFF RECOMMENDATION:

Informational filing – no recommendation.

DISCUSSION:

Issue

This report provides an updated estimated rate impact analysis for the Community Solar Program alternate interim bill credit rate.

Applicable Law

Section 22 of Senate Bill (SB) 1547, effective March 8, 2016, directs the Public Utility Commission of Oregon (Commission) to establish a program that provides electric customers with the opportunity to share the costs and benefits of solar generation (hereinafter referred to as "Community Solar Program", "Program" or "CSP"). Community Solar Program participants bear a portion of the cost to construct and operate a solar facility and receive a bill credit from their electric company for their portion of the solar facility's output.

SB 1547, sec. 22(6)(a) specifies that electric companies shall credit CSP participants for their proportional shares of CSP project generation "in a manner that reflects the resource value of solar" and directs the Commission to determine the resource value of solar energy (RVOS). However, sec. 22(6)(b) provides that the Commission may adopt a rate for an electric company to use in crediting a participant's electric bill that does not

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April 10, 2018

reflect the resource value of solar “if the Commission has good cause to adopt the different rate.” The legislation also provides the Commission authority to suspend the program for good cause.¹

On June 29, 2017, the Commission adopted formal rules for Oregon's Community Solar Program through Order No. 17-232. That order adopted Division 88 of Chapter 860 of the Administrative Rules, which includes the following directive to establish the bill credit rate based on the RVOS:

Unless otherwise determined by Commission order, the bill credit rate for a project will be based on the resource value of solar applicable to that project at the time of pre-certification and will apply for a term no less than the term of any power purchase agreement entered into pursuant to OAR 860-088-0140(l)(a).²

OAR 860-088-0060 establishes the Program Capacity Tier, which is the amount of total program capacity eligible for projects participating in an electric company's service territory. The Program Capacity Tier for each electric company is equal to 2.5 percent of the electric company's 2016 system peak and the Commission can establish successive capacity tiers.³

In Order No. 18-088, the Commission determined there is good cause to develop an interim alternative bill credit rate, due to issues of timing and value associated with the application of RVOS as the initial CSP bill credit rate. At the April 24, 2017 Public Meeting, the Commission adopted the Simple Retail Rate as the interim alternate bill credit rate for the first 25 percent of capacity of the Program Capacity Tier. The Simple Retail Rate (hereinafter referred to as the “interim rate”) for each electric company is equal to the electric company's volumetric standard residential retail rate.

Analysis

Background

At the April 10, 2018 Public Meeting, Staff presented three interim alternative bill credit rate (interim alternative rate) proposals for Commission consideration. In its report, Staff proposed that the Commission evaluate whether to transition to RVOS or continue with the interim alternative rate when 50 percent of the Program Capacity Tier is reached. Staff's report provided an estimated rate impact analysis for each proposed interim alternative rate. The rate impact methodology estimated the incremental cost of applying the alternative interim bill credit rate to 50 percent of the Program Capacity Tier for 20 years, over the cost of applying the standard solar qualifying facility (QF) avoided cost rate for the same capacity and term.

¹ Senate Bill 1547, Section 22 (2)(c).

² Oregon Administrative Rules 860-088-0170 (1)(a).

³ Oregon Administrative Rules 860-088-0060 (1) - (3).

UM 1930
 April 10, 2018

This report provides an update to Staff's estimated rate impact analysis to reflect the Commission decision to apply the interim rate for 25 percent of the Program Capacity Tier.

Updated Rate Impacts

The estimated rate impacts represent the incremental cost to ratepayers for purchasing the output from CSP projects at the interim rate, over the cost to purchase the output at the real levelized standard solar QF avoided cost rate. The QF avoided cost rate is the best reflection of both the costs and the value of solar generation currently available, i.e., QF avoided cost represents a break-even point, over which the rate will reflect the generation's costs in excess of the generation's value. Staff notes that RVOS would be a better reflection of the breakeven point if Commission adopted RVOS values were available.

Estimated Rate Impacts - Simple Retail Rate				
	25% of Program Capacity Tier (MW)	Estimated Bill Credit Rate (\$/kWh)	Estimated rate impact of interim rate (\$)⁴	Rate impact as a percentage of revenue requirement⁵
PGE	23.29	\$0.1103	\$29,408,312	0.062%
PAC	16.15	\$0.1005	\$21,294,328	0.065%
IPC	00.82	\$0.0880	\$1,002,867	0.068%⁶

Conclusion

The Commission adopted the Simple Retail Rate as the interim alternate bill credit rate for the first 25 percent of the Program Capacity Tier. This report provides an updated analysis of the impact to ratepayers of crediting participants at this rate and capacity level over 20 years.

PROPOSED COMMISSION MOTION:

N/A

UM 1930 Updated Rate Impact Analysis

⁴ Staff's estimate assumes that the program is fully subscribed up to the interim Program Capacity Tier (~40.26 MW) for 20 years (the minimum PPA term for CSP projects). Estimated rate impacts are in real 2018 dollars gross over 20 years.

⁵ Percentages represent the gross rate impact as a percentage of revenue requirement from 2018 - 2037.

⁶ The IPC *Rate impact as a percentage of revenue requirement* estimate reflects a corrected revenue requirement figure. The analysis provided in Staff's April 10, 2018 report utilized a \$1,206,447 2018 revenue requirement; this analysis represents a \$55,648,472 2018 revenue requirement.

Appendix B

OPUC Staff Memo: Community Solar Implementation Update July 24, 2018

ITEM NO. 4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: July 31, 2018

REGULAR	X	CONSENT	EFFECTIVE DATE	N/A
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DATE: July 24, 2018

TO: Public Utility Commission

FROM: Caroline Moore ^{CM}

THROUGH: Jason Eisdorfer and JP Batmale ^{JE} ^{JP}

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. UM 1930) Community Solar Program Implementation Update.

STAFF RECOMMENDATION:

Informational filing - no recommendation.

DISCUSSION:

Issue

This report provides an update on the status of UM 1930 Community Solar Program Implementation. The report will include updates on the following implementation activities:

- Program Administrator Request for Proposals,
- Subgroup activities,
- Administrative cost recovery processes, and
- Preparation for the transition to full implementation.

Applicable Law

Section 22 of Senate Bill (SB) 1547, effective March 8, 2016, directs the Public Utility Commission of Oregon (Commission) to establish a community solar program (hereinafter referred to as "Community Solar Program", "Program" or "CSP"). The CSP, codified in Oregon Revised Statute (ORS) 757.386, provides electric company customers an opportunity share in the costs and benefits of solar photovoltaic (PV)

generation. Further, the statute requires that ten percent of CSP capacity is available for low-income residential customers.¹

On June 29, 2017, the Commission issued Order No. 17-232, which adopted the rules for CSP implementation. Set forth in Division 88 of Chapter 860 of the Administrative Rules, these rules specify that the Commission will select a CSP Program Administrator (PA) through a competitive bidding process.² OAR 860-088-0020 outlines the PA's responsibility to support the Commission's implementation and ongoing management of the CSP, which includes:

- Developing the Program Implementation Manual (PIM) in collaboration with Commission Staff;
- Facilitating the multi-step process for the Commission to certify projects for participation in the program;
- Facilitating the calculation and exchange of large amounts of data and monies between utilities, Project Managers, and CSP participants;
- Coordinating with the Low-Income Facilitator (LIF) to meet the CSP's low-income requirements; and
- Supporting the Commission and utilities in implementing the consumer protection requirements set forth in the CSP rules.

Through Orders No. 17-372 and 17-458, the Commission approved Staff's preliminary implementation process. The process approved by the Commission focuses on competitive procurement of the PA services and efforts to scope and examine major implementation issues in coordination with stakeholders.

Commission Order 18-177, issued May 23, 2018, directs Staff to present a status update for CSP implementation at a public meeting in July.³ This memo will provide a CSP status update that focuses on procurement of the PA services and efforts to examine major implementation issues in preparation for the PA.

Analysis

Background

Through Order No. 17-372, issued September 28, 2017, the Commission adopted Staff's recommended next steps for CSP implementation. In addition to the issuance of a Request for Proposals (RFP) for PA services, the Commission directed Staff to report back with implementation action recommendations following stakeholder workshops.⁴

¹ ORS 757.386(9)(a).

² Oregon Administrative Rules 860-088-0020(1).

³ Order No. 18-177, p.5.

⁴ Order No. 17-372, Appendix A, p .6.

Staff conducted a CSP implementation workshop on October 19, 2017. Stakeholders and Staff agreed upon a series of implementation action items and priorities that could commence prior to selection of the PA.⁵ This implementation plan focused on the formation of topical subgroups. These stakeholder-driven groups are responsible for identifying, prioritizing, and evaluating CSP implementation issues in preparation for the PA.⁶

On January 30, 2018, Staff presented an update on CSP implementation actions to the Commission. Staff reviewed subgroup activity and categorized subgroup issues as follows:

- Items of subgroup consensus to be memorialized for use in developing the PIM;
- Items of subgroup consensus to bring to the Commission for consideration under UM 1930; and
- Items that require further examination under UM 1930.⁷

The Commission adopted Staff's recommended categorization of items, and included amendments that accelerated consideration of an interim alternative bill credit rate for CSP participants.^{8,9}

Staff held an informal stakeholder workshop on January 31, 2018 to review the outcome of Staff's January 30, 2018 report. Upon further review, stakeholders raised two issues concerning the categorization of consensus items:

1. **Consensus items to be memorialized for the PIM:** Stakeholders agreed that these items required additional refinement within the subgroups prior to memorialization.
2. **Consensus items to bring to the Commission:** Stakeholders agreed that these items required additional scoping and consideration. Stakeholders also expressed concern about the ability to refine these items to the point of Commission consideration absent the PA. Staff and stakeholders agreed that these items should be converted into items to be memorialized for use in developing the PIM.

⁵ See AR 603, Staff memo to Commissioners presented at the November 7, 2017 Public Meeting, subsequently approved as Order No. 17-458.

⁶ For more details on the initial subgroups' scope, see Order No.18-042, Appendix A pp. 21-60.

⁷ Order No.18-042, Appendix A, pp. 17 – 20.

⁸ Order No.18-042.

⁹ ORS 757.386(6)(a)-(b) direct utilities to credit CSP participants for their portion of the community solar project's generation. The bill credit rate must reflect the Resource Value of Solar (RVOS), unless the Commission determines there is good cause to establish an alternative bill credit rate. See Order No. 18-177 for details on the alternative interim bill credit rate. See dockets UM 1716, UM 1910, UM 1911, and UM 1912 for more details on the RVOS.

Following the January 31, 2018 workshop, subgroup efforts paused so that members could focus on pressing matters associated with the consideration of an interim alternative bill credit rate. On May 23, 2018, the Commission issued order 18-177, which established an interim alternative bill credit rate for the CSP. While additional implementation issues remain, the Commission order provided critical guidance for project and program development. Following the establishment of an interim alternative bill credit rate, the subgroups resumed focus on additional key implementation topics.

Efforts to resume focus on additional implementation issues began with an informal workshop on June 13, 2018. The workshop covered two topics:

1. Re-scoping subgroup efforts in preparation for PA onboarding.
2. Initial discussion of administrative cost recovery processes.

The remainder of this memo will review key CSP implementation efforts following the June 13, 2018 workshop, as well as, provide an update on the status of the RFP for PA services.

RFP Update

Staff continues to progress toward PA selection and anticipates issuing the Notice of Intent to Award before the end of this quarter. Key RFP milestones and next steps are summarized below.

Acting on behalf of the Commission, the Department of Administrative Services (DAS) released the RFP for PA services on April 16, 2018. A bidders conference was held on April 25, 2018 with approximately fifteen in person and phone attendees. The RFP closed on May 31, 2018.

DAS remains the single point of contact for the RFP during evaluation and selection. Staff is coordinating with DAS to ensure a robust evaluation and selection process. While Staff is taking steps to ensure an expedient process, it continues to focus its efforts on selecting the right vendor to provide these critical and complex services.

Staff intends to notify the Commission at a public meeting when the Notice of Intent to Award is issued.

Update from the Subgroups

Throughout June and July 2018, Staff and stakeholders worked collaboratively to continue moving implementation forward in preparation for the PA. At the June 13, 2018 subgroup re-scoping workshop, stakeholders agreed to the following subgroup actions:

- Focus on identifying issues and outlining major considerations to help expedite PA onboarding and the development of the PIM;

- If consensus on an issue is achieved, memorialize the recommendation to support development of the PIM;
- If consensus is not achieved, document major considerations raised during subgroup discussion as a resource for the PA;
- Continue to discuss issues under three existing subgroups:
 - Funding, Data and Financial Exchange, Billing Tariffs Subgroup (hereinafter referred to as “Utility Data Exchange”)
 - Project Details Subgroup
 - Low Income Subgroup;
- Hold further discussion of RVOS/Bill Credit Rate Subgroup issues until PIM development commences; and
- Form a new subgroup focused on consumer protection issues (Consumer Protection Subgroup).

Following the workshop, each subgroup convened an initial meeting. Each subgroup’s status is summarized in the table below. A full update from each subgroup is provided in Attachments A – D of this report.

At present, the subgroups are scheduling the next meeting and assembling information to support discussion of identified issues. For example, the Low Income Subgroup formed a subcommittee to gather background research that will inform subgroup consideration of low-income incentives. In another example, the Project Details Subgroup identified issues related to the utility treatment of community solar projects from an interconnection standpoint e.g., will utilities be required to provide Network Resource status to CSP projects, similar to a Qualifying Facility? A subset of members agreed to develop a series of interconnection scenarios to help inform forthcoming decisions.

Subgroup	Key Developments Since January Status Update	Current Status
Utility Data Exchange ¹⁰	<ul style="list-style-type: none"> • Updated the recommended tariff filing schedule (e.g., PPA between the utility and Project Manager, start-up cost recovery, participant tariffs, utility project tariffs.) • Determined that customer data privacy should be moved to the scope of the Consumer Protection Subgroup. • Identified new questions about: <ul style="list-style-type: none"> ○ Collection of administrative costs from participants across multiple on-bill payment models, and for projects that utilize an alternative to on-bill collection. ○ The treatment of banked kWh and differential credits when customers terminate participation.¹¹ ○ The potential for rate schedules with low volumetric charges to accrue large differential credit banks.¹² ○ The ability of utilities to recover ongoing administrative costs.¹³ 	<ul style="list-style-type: none"> • Met July 9, 2018. • Scheduling next meeting in mid-August. • The Subgroup agreed to continue to investigate scenarios related to the banking of kWh and monetary credits. • Staff requested feedback from subgroup members regarding the types of alternative subscription models being contemplated and why they could be preferable to the on-bill collection model.
Project Details ¹⁴	<ul style="list-style-type: none"> • Confirmed consensus around the minimum requirements for interconnection status to receive pre-certification. • Identified new questions related to utility obligations and the classification of CSP projects during interconnection, including: <ul style="list-style-type: none"> ○ Whether projects receive network resource status? ○ Which entity is responsible for system upgrade costs? ○ Which interconnection application is most appropriate for this project type? 	<ul style="list-style-type: none"> • Met July 9, 2018. • Meeting July 26, 2018. • Staff requested that subgroup members develop a catalogue of potential project interconnection scenarios to support evaluation of utility obligations and the classification of CSP projects during interconnection.

¹⁰ This group focuses on requirements for utilities in facilitating participation in the program and the exchange of data between the utilities, PA, project managers, and participants. See Attachment A for additional details.

¹¹ OAR 860-088-0170 allows participants to carry over excess kWh and dollar values if their monthly credit exceeds what is allowed under the rules.

¹² Differential credit means the difference between the retail rate multiplied by the participant's eligible generation, and the bill credit rate multiplied by the payable generation (See OAR 860-0170(1)(c).) If the participant's rate schedule provides a lower per kWh charge than the bill credit rate, the participant may accrue a deferential credit. The rules do not provide a mechanism to donate or otherwise monetize the differential credit.

¹³ The rules do not directly address ongoing administrative costs borne by the utilities in facilitating on-bill crediting and other CSP requirements.

¹⁴ This group focuses on CSP project requirements and certification processes. See Attachment B for additional details.

<p>Low Income¹⁵</p>	<ul style="list-style-type: none"> • Continued discussion of the threshold to define low-income eligibility. • Identified new questions surrounding the ability of housing providers to hold CSP subscriptions on behalf of low-income customers. • Identified the need to resolve questions related to the role of housing providers before landing on recommendations for portability, transferability, and early termination of low-income subscriptions. • Identified questions related to the need for and use of financial incentives for low-income participation.¹⁶ 	<ul style="list-style-type: none"> • Met July 16, 2018. • Scheduling a meeting in mid-August. • Scheduling subcommittee meetings/work plans to address the following: <ul style="list-style-type: none"> ○ Developing Low Income Principles and Equity Metrics for key elements of program implementation. ○ Outlining potential scenarios under which housing providers could hold subscriptions on behalf of low-income customers. ○ Identifying potential low-income incentive structures, including a review of other states' models.
<p>Consumer Protection¹⁷</p>	<ul style="list-style-type: none"> • Discussed the scope and priorities of the newly formed subgroup. • Identified new questions related to: <ul style="list-style-type: none"> ○ Participation terms e.g., transferability and portability of subscriptions. ○ Required consumer resources e.g., web portal, checklists, fact sheets. ○ Contract and disclosure language. ○ Protections unique to owners versus subscribers. 	<ul style="list-style-type: none"> • Met July 18, 2018. • Scheduling a meeting in August. • Subcommittee researching other states' CSP consumer protection practices. • Subcommittee outlining consumer protection considerations unique to ownership models.

Staff greatly appreciates the continued efforts of the subgroup leaders and members. The subgroups continue to produce thoughtful discussion and raise important implementation issues. This work will accelerate PA onboarding and materially benefit the PIM development process.

Cost Recovery Issues

Certain cost recovery issues directly impact the Commission's ability to bring the PA on board. For example, the PA cannot begin executing the contract without a system in

¹⁵ This groups focuses on issues unique to supporting low-income participation and meeting low-income requirements. See Attachment C for additional details.

¹⁶ OAR 860-088-0080(4) allows the Commission to establish a funding mechanism to facilitate participation of low-income residential customers.

¹⁷ This is a newly formed group that focuses on consumer protection requirements and best practices. See Attachment D for additional details.

place to remit payment for services. Consequently, Staff is leading this discussion on a separate track from the subgroups.

Utilities, stakeholders, and Staff began outlining the process to recover CSP administrative costs at the June 13, 2018 workshop. The initial discussion focused on the process to recover start-up administrative costs, which was identified as the most pressing issue.¹⁸

At the workshop, the utilities committed to developing brief proposals for start-up administrative cost recovery within approximately 60 days. The utilities will propose the following:

- The allocation of start-up administrative costs across utilities;
- The mechanism by which each utility will recover start-up costs associated with the PA and the Low Income Facilitator (LIF); and
- The mechanism by which each utility will recover its prudently-incurred start-up costs.

Once proposals are submitted, Staff will schedule a follow-up workshop where stakeholders and Staff will ask clarifying questions and provide feedback to the utilities. Following the workshop, Staff will bring a recommendation for next steps to the Commission at a public meeting. Upon approval, the utilities will file tariffs consistent with Commission direction.

Concurrently, utilities, stakeholders, and Staff will continue to scope and address additional recovery issues. For example, stakeholders have raised questions about each utilities' ability to recover its prudently-incurred ongoing administrative costs, such as the costs to facilitate monthly bill credits and exchange of data with the PA.

Staff will keep the Commission informed as to the status of administrative cost recovery issues. Staff plans to provide an update at a Public Meeting no later than August 31, 2018.

Preparation for the Transition to Full Implementation

Staff recognizes that efforts under UM 1930 are approaching a transition point. When the PA contract is executed, implementation efforts must accelerate from the preliminary actions taken to date, to an extensive catalogue of implementation activities that will begin as soon as the PA is on board.

¹⁸ ORS 757.386(7) and 860-088-0160 allow CSP start-up costs to be recovered in utility rates, and require ongoing costs to be borne by CSP participants.

At this stage of the RFP process, Staff has visibility into the timeframe to execute a contract with the PA. In addition, the subgroups continue to flesh out the major themes and issues surrounding CSP implementation. With support from these insights, Staff is shoring up its strategy and resources for the full implementation phase. Staff's efforts are described below.

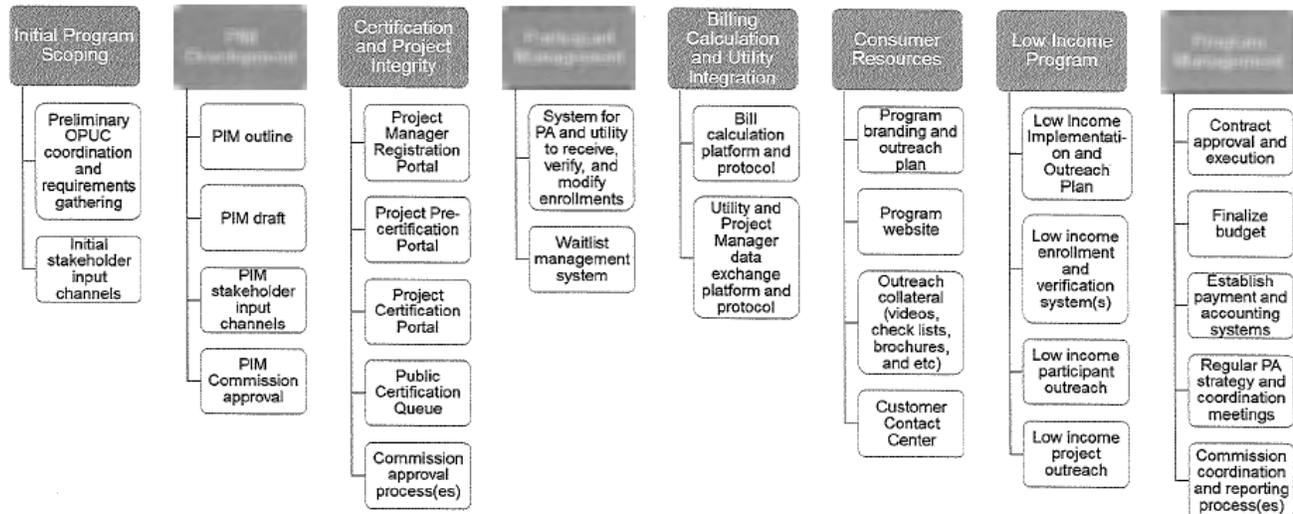
Currently, Staff is focused on the following:

- Finalizing its internal project plan,
- Allocating necessary resources,
- Developing channels to bring issues and recommendations to the Commission,
- Placing more precise timeframes on important program milestones, and
- Tackling major design questions such as project diversity and additionality.

Staff's plan relies on close collaboration with the Commission and stakeholders to navigate implementation milestones, and work through the breadth of implementation issues.

The diagram below demonstrates some of the major implementation work streams required for program launch. Staff assumes this plan will be executed within approximately 6 months. Staff's planning efforts are non-exhaustive at this stage, and will be heavily informed by the PA, stakeholders, and direction from the Commission in the very near future.

Preliminary CSP Launch Work Streams, Anticipated Subtasks, and Deliverables



Conclusion

The CSP is quickly approaching an important transition to full program implementation activities. Staff, in collaboration with DAS, continues to make progress toward selection of the Program Administrator, which may be completed as soon as this quarter. Stakeholders have been very helpful to Staff and have made significant headway toward identifying and evaluating issues in the interim. As the transition to full implementation approaches, Staff will continue its efforts to refine its internal project plan, allocate necessary resources, develop formal channels to bring issues and recommendations to the Commission, place more precise timeframes on important program milestones, and tackle key design questions.

PROPOSED COMMISSION MOTION:

Informational filing - no recommendation.

UM 1930

Oregon Community Solar – Utility Data Exchange Subgroup

Summary - July 9, 2018 Meeting

Attendees: Erik Anderson (PacifiCorp), Nate Larsen (PacifiCorp), Natasha Soares (PacifiCorp), Kevin Vielbaum (NRG), Todd McConachie (PGE), Kelly Noe (Idaho Power), Charlie Coggeshall, Lucas Kappel (BEF), Caroline Moore (OPUC), Ken Nichols (EQL Energy), Dave McClelland (ETO), plus others.

Objective: The Utility Data Exchange Subgroup, which last met in December 2017, was reconvened to inform the eventual Community Solar Program Administrator on topics relevant to the development of the Program Implementation Manual.

This meeting was organized around the topics provided by Commission Staff in its UM 1930 Community Solar Implementation Workshop on June 13, 2018:

Subgroup	Memorialize for PA (Priority items that can reach consensus recommendation prior to PA)	Continue discussion (Priority items that do not require PA to initiate)	Hold for PA (Non-consensus, non-priority, or items that require PA)
Utility Data Exchange	<ul style="list-style-type: none"> Updated tariff filing schedule Customer data privacy agreement On-bill collection models On bill display recommendations 	<ul style="list-style-type: none"> Administrative cost recovery 	<ul style="list-style-type: none"> On-bill alternatives process and guidelines Customer data privacy agreement PA – Utility interface

Areas of Discussion

1. Updated tariff filing schedule

The subgroup previously identified several tariffs and regulatory filings necessary to implement the Community Solar Program; in this meeting, the subgroup discussed revisions to the originally identified tariffs and filings. The revisions considered are described below:

-

Issue	Who	Initiated?	Other considerations
Standardized QF/PPA Agreement between the utility and Project Managers for unsubscribed energy	Each utility	Q4 2018/ Q1 2019	The Project Details Subgroup is currently considering the issue of whether community solar projects are QFs. The development of a standard agreement requires resolution of this issue.
Utility administrative cost recovery methodology discussions/filing	Each utility	Start-up costs Q3 2018	Start-up costs: utilities will set up balancing accounts and file a deferral for cost recovery.
		Ongoing costs Q4 2018/Q1 2019	Ongoing costs: unresolved whether the language in Order 17-232 permits utility recovery of ongoing administrative costs. Utilities would file tariffs identifying ongoing

			administrative costs to be recovered from community solar participants. PacifiCorp proposed recovery of bill credit costs and PPA (unsubscribed energy) costs as net power costs through its transition adjustment mechanism (TAM).
Community Solar Program tariff for customers	Each utility	Q4 2018/ Q1 2019	Subscription fees will be project specific, and the bill credit rate may change over time. There was general consensus among the subgroup that a community solar tariff for customers could include a hyperlink to a table of project specific subscription fees and bill credit rates.
Utility-managed project tariff	Each utility	Upon decision to initiate project	Utility-managed projects included in the table of project specific subscription fees and bill credit rates.
Data privacy docket	PA		Topic reserved for Consumer Protection Subgroup discussion.

2. Customer data privacy agreement

The Subgroup concluded that this was an issue better addressed by the Consumer Protection Subgroup.

3. On bill collection models

Several issues arose regarding on-bill collection models:

Topic	Issue	Subgroup Guidance
<p>The Subgroup identified several possible subscription models:</p> <ul style="list-style-type: none"> Per kWh (variable) Per kW (fixed) Alternative structures (including upfront payment of subscription fees, off-bill fee collection, &c.) 	<p>Three questions arose in this context:</p> <ul style="list-style-type: none"> How should administrative costs be recovered in these models? 	<ul style="list-style-type: none"> A potential approach to recovering administrative costs would be to charge a participant based on the capacity of the project to which they subscribe, divided by the participant's share of that project (i.e. their individual capacity).
	<ul style="list-style-type: none"> Are administrative costs recoverable from participants who subscribe to projects that employ alternative subscription models? 	<ul style="list-style-type: none"> The Subgroup consensus was that it would be inequitable to permit Project Managers and participants who employ alternative subscription models to avoid paying the appropriate share of administrative costs.

	<ul style="list-style-type: none"> When can project managers use alternative subscription models? 	<ul style="list-style-type: none"> Commission Staff requested feedback from likely Project Managers regarding the types of alternative subscription models being contemplated and the reasons why they are preferable to the on-bill collection model.
<p>Banked credits, two types:</p> <ul style="list-style-type: none"> Banked kWh ("carry-over generation") Banked monetary credits ("differential credit") 	<p>Several questions:</p> <ul style="list-style-type: none"> What happens to a participant's banked credits if they move out of the utility's service territory? <hr/> <ul style="list-style-type: none"> At the current bill credit rate, are there circumstances that would create a monetary credit for participants? 	<ul style="list-style-type: none"> The Subgroup's initial instinct was that kWh credits for participants who leave the service territory should roll into low income programs, as they do in the case of excess generation. Monetary credits, to the extent a customer receives any, should be paid out. <i>However, the Subgroup ultimately concluded that this question better suited for the Consumer Protection Subgroup.</i> <hr/> <ul style="list-style-type: none"> Participants may accrue monetary credits to the extent that their bill credit rate minus any subscription fees exceeds the retail rate that they pay for electricity. This issue appears to be limited to the context of commercial and industrial customers whose retail rates are lower than the bill credit rate. <p>The Subgroup agreed to continue to investigate scenarios related to the banking of kWh and monetary credits. Charlie Coggeshall offered to circulate a bill credit calculator that he developed that might assist the Subgroup in exploring the issue.</p>

4. On bill display recommendations

Utilities have different billing systems and will have different abilities to display information on customers' bills. There was general consensus among the Subgroup that its previous work in identifying types of information that the utilities should include on customers' bills is appropriate:

Characteristic	Included? Where?	Discussion
Facility Name	Yes, description somewhere	Probably needs to be something descriptive rather than too short
Admin Costs	Yes, separate line	There seemed to be consensus that this should be displayed separately. May be some concern that this adds an extra line. Fixed fee, or a kWh rate x eligible generation
kWh Produced	Yes, credit line/per kWh subscription fee line	Included in credit line with credit rate to show total credit. Also shown in per kWh model for computation of subscription fee
RVOS/Credit Rate	Yes, credit line	Included in credit line to show total credit the differential credit (\$) + (eligible generation (kWh) x bill credit rate (\$))
Per kWh rate	For per kWh customers, subscription fee line	Included in subscription fee line to explain amount.
Lease rate and shares purchased	No	Not important to include breakdown of how subscription fee is calculated if it does not vary throughout the year, and conforms with contracts provided to customers.
Banked kWh	Yes, somewhere	Group thought this value is important to include on bills
Differential Credit Bank	Yes, somewhere	Group thought this value is important to include on bills

5. Next Steps

Members of the Subgroup committed to following up on the following action items:

- Scope of possible alternative subscription models
 - Charlie Coggeshall will discuss alternative subscription models with potential Project Managers and present proposed models and reasons for deviation from the on-bill credit model to the Subgroup and Commission Staff.
- Utility administrative cost recovery (action item from June 13 OPUC workgroup)
 - Utility representatives will develop and present proposed approaches to recover the following administrative costs:
 - Start-up costs
 - Ongoing administrative costs
 - Power (bill credit/PPA) costs
- Program Administrator policy considerations
 - Tee up any policy questions that might arise for Program Administrator
- On-bill credit models
 - Look at utility data exchange flow chart and clean up as necessary

UM-1930 Project Detail Subgroup Meeting Minutes

July 9, 2018

Members Present: Jon Miller, Kelley Noe (+ 3 others from Idaho Power), Ken Nichols, Rikki Seguin, Lizzie Rubado, Daniel Hale, Caroline Moore, Michael Chestone, Charlie Coggeshall, Michael Cathcart, Lucas Kappel, Erik Anderson, Nate Larsen, Natasha Siores, Clair Carlson, Ryan Sheehy, Sean Micken, Justin Wilson.

Next meeting: TBD, tentatively targeting a day during the last week in July (23rd-27th)

Our discussion started with an Intro to the project details group items as proposed in the matrix sent out by PUC staff. Staff made it clear the matrix was a proposal only and the groups should endeavor to identify important issues that should be discussed. At the end of the meeting a request was made for members to submit issues in writing for the group to consider. Several examples are included below.

The primary issue discussed by the group was interconnection issues related to project classification (QF or not a QF, Network Resource vs Energy Resource), interconnection applications and agreements. Members were asked to submit example projects to illustrate issues that could arise. See below for details.

A question was brought up about the work that the Project Details (PD) group is providing. It was reiterated that the PD Group's main purpose is to provide input and clarifications to the Commission and the Commission would make any final formal decisions on rule interpretations. The PD Group is not empowered beyond providing input to the eventual Program Administrator and the Commission.

1. Project pre-certification interconnection requirement discussion

Consensus Item: The group re-confirmed that either a completed system impact study or a completed interconnection agreement would suffice to meet the pre-certification interconnection requirement in the rules (July 29th 2017, order #17 232).

Note the pre-certification section 860-088-0040(d) states "All documentation relevant to the interconnection process as provided in OAR chapter 860, division 82", inferring that additional documentation may be required to fully comply with pre-certification interconnection requirements. However, the consensus that projects with completed system impact studies would be sufficient (with accompanying relevant interconnection documentation) as opposed to only allowing systems with executed interconnection agreements is an important distinction.

2. Project interconnection classification

The group had a lot of discussion around the appropriate classification of projects and whether they were QF projects, not QF projects, or something in between. This issue will need to be resolved prior to the community solar program moving forward.

Issues discussed included:

- The general classification of the projects as QF or not QF was discussed and no general agreement was reached. It became obvious that this issue is very important to resolve, but also that it may not be easily resolved without Commission involvement.

Even though we may not reach consensus, the group decided to continue the discussion to provide feedback to the Commission to clarify how community solar projects should be classified as this could have major ramifications on interconnection process, cost recovery, project energy re-imbursement values, and it's the long lead development task that could stall the program if not defined early.

- Whether projects were Network Resource or Energy Resource was also discussed and no general agreement was reached. This issue is connected to the general classification of the projects and further discussion is required.

Action Item: Create several project scenarios (4-6?) that illustrate distinct and likely project scenarios that capture the most relevant situations and then analyze these scenarios to determine how different classifications might be affected. The goal is to use the scenarios to assist with determining how projects should be classified.

Action Item: Define Network Resource and Energy Resource and their possible application to community solar projects.

Project Scenario Examples (input needed):

A spreadsheet matrix could be developed to compare these scenarios. All systems assumed to be installed on distribution networks. Example below is illustrative only, please provide alternative matrix structure and questions.

	Site	Network	Local Network Capacity?	Transmission required to reach subscribers?	How does QF vs non-QF impact this project?	How does NR vs ER impact this project?	Why is QF or not QF appropriate for this project?	Why is NR or ER appropriate for this project?
Project One	< 360kw	Distribution	> than project	no				
Project Two	< 360kw	Distribution	< than project	yes				
Project Three	> 360kw, <or= 3MW	Distribution	> than project	no				
Project Four	> 360kw, <or= 3MW	Distribution	< than project	yes				
Project Five	> 3MW (wants to transition part to CS program)	Distribution	< than project	yes				

3. Interconnection process, application, and agreement

There appeared to be a general agreement that new applications and agreements may have to be created to capture the community solar program projects. We did not discuss this issue in detail as the previous issue (project classification and ER/NR issues) will likely need to be resolved first.

Action Item: Verify whether there's agreement that new applications and agreements are needed and explore how long this will take and what they will look like (IE are they very similar to the other applications and agreements?). Can this be done prior to defining the project classification?

Action Item: Define the interconnection process / rules for community solar projects. Should we assume only the use of OAR Chapter 860 Division 82 rules? Division 29 rules were brought up in the meeting, however, the July 29th 2017 rules only reference Division 82 rules.

4. Additional items for potential group discussion

Near the end of the meeting several potential additional items to consider were briefly mentioned. The group briefly discussed whether low hanging fruit items that would be easier to reach consensus on

should be brought up first. The group was asked to come up with those items by submitting them to Jon Miller to be added to a list for consideration.

A question about the future of the PD group was brought up. It seems highly likely that when a PA is on board the PD group will handover all material and future meetings will be run by the PA.

Example potential issues/questions provided so far include:

- Section 860-088-0040. Section (4) states the Project Manager may execute contracts with participants for ownership or subscription interests after pre-certification is granted. The assumption is that Project Managers can engage with potential subscribers prior to pre-certification and the only prohibition is executing an ownership or subscription agreement?
- Section 860-088-0070. Co-location requirements need further definition. They reference a 5-mile radius and a 3MW limit or installed in a single municipality or defined urban area. Is there a size limit? What can be co-located?
- Section 860-088-0040. Section (6) states the Project Manager must seek Commission approval of any modification to a pre-certified project. What happens if some event prohibits a project manager that has achieved precertification and enrolled subscribers cannot receive energy from the pre-certified project? For example, a project manager has a PPA with a developer, achieves precertification and begins to enroll subscribers, and an intervening event occurs that prevents the project from coming online (environmental sensitivity, land use issue, bankruptcy, etc). Does the PM keep the pre-certification and find another project or does the pre-certification belong to the project (which would imply that if the project fails, the pre-certification is rescinded)?

Action Item: Group members to submit additional questions or issues that the PD group can consider for future discussions.

MOORE Caroline

From: Jaimes Valdez <jaimes@sparknorthwest.org>
Sent: Monday, July 23, 2018 7:53 AM
To: MOORE Caroline; Oriana Magnera; Jon Miller
Cc: Anderson, Erik
Subject: RE: UM 1930 Subgroup - Commission status reports
Attachments: Community Solar Low-Income Workgroup Notes_ 7_17.docx; Low Income Community Solar Implementation - Topic Worksheet July 23.xlsx

Hi Caroline,

Thanks Caroline, and apologies for delay.

Here (below) is the update from the Low Income Subgroup, and notes from the meeting and the table are attached:

- The group met once on July 16, 2018 to scope out the topics that the commission tasked us with, as well as a few that were added by group members.
- The attached table reflects the topics and the decision points that the group agreed to.
- We reviewed the previous group report from Dec 2016, and revisited some of the recommendations. While we had intended to affirm the past groups' conclusions, there was a need for greater discussion before formalizing recommendations.
- Generally, there is a desire from the group to know more about who is selected in the low-income facilitator role before committing to an approach on the income threshold. The reason is this may impact the income verification process and opportunities to partner with existing pathways to deliver services. There is also an active discussion about whether it is better to make the low-income threshold applicable to more people, or to target it more specifically to those who need it most.
- The group identified a need to resolve the outstanding decisions around the potential role of housing providers in the program before landing on recommendations around portability, transferability, and early termination of subscriptions. Also, there is a need to track some of the discussion of the consumer protection subgroup first, to understand whether there are general contract terms for all customers, or whether low income customers have some exceptions to certain of these provisions.
- Members of the group agreed to do work in the following weeks on three topic areas, and teams were created to further develop material on:
 - * Low Income Principles and Equity Metrics for key elements of the program implementation. (Led by Jaimes)
 - * Housing Providers, and their potential role in the program. This team will provide some models of how housing providers could play a role in managing subscriptions, to help inform DOJ and Commission staff in making a legal determination. (Led by Jaimes)
 - * Incentive structures to support low income customers. This team will provide some models of possible incentive structures, to help inform DOJ and Commission staff in making a legal determination on this topic. (Led by Oriana)
 - * These team meetings are being scheduled.
- The Low Income Subgroup intends to meet again in mid August, with reports back from the topic teams and additional discussion.

I hope this is an adequate amount of detail, and let me know if you have any questions.

Thanks!

-Jaimes

Oregon Community Solar – Utility Data Exchange Subgroup

Summary - July 9, 2018 Meeting

Attendees: Erik Anderson (PacifiCorp), Nate Larsen (PacifiCorp), Natasha Soares (PacifiCorp), Kevin Vielbaum (NRG), Todd McConachie (PGE), Kelly Noe (Idaho Power), Charlie Coggeshall, Lucas Kappel (BEF), Caroline Moore (OPUC), Ken Nichols (EQL Energy), Dave McClelland (ETO), plus others.

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Areas of Discussion

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The subgroup previously identified several tariffs and regulatory filings necessary to implement the Community Solar Program; in this meeting, the subgroup discussed revisions to the originally identified tariffs and filings. The revisions considered are described below:

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The Subgroup concluded that this was an issue better addressed by the Consumer Protection Subgroup.

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Several issues arose regarding on-bill collection models:

Topic	Issue	Subgroup Guidance
<p>The Subgroup identified several possible subscription models:</p> <ul style="list-style-type: none"> • Per kWh (variable) • Per kW (fixed) • Alternative structures (including upfront payment of subscription fees, off-bill fee collection, &c.) 	<p>Three questions arose in this context:</p> <ul style="list-style-type: none"> • How should administrative costs be recovered in these models? • Are administrative costs recoverable from participants who subscribe to projects that employ alternative subscription models? 	<ul style="list-style-type: none"> • A potential approach to recovering administrative costs would be to charge a participant based on the capacity of the project to which they subscribe, divided by the participant's share of that project (i.e. their individual capacity). • The Subgroup consensus was that it would be inequitable to permit Project Managers and participants who employ alternative subscription models to avoid paying the appropriate share of administrative costs.

	<ul style="list-style-type: none"> • When can project managers use alternative subscription models? 	<ul style="list-style-type: none"> • Commission Staff requested feedback from likely Project Managers regarding the types of alternative subscription models being contemplated and the reasons why they are preferable to the on-bill collection model.
<p>Banked credits, two types:</p> <ul style="list-style-type: none"> • Banked kWh (“carry-over generation”) • Banked monetary credits (“differential credit”) 	<p>Several questions:</p> <ul style="list-style-type: none"> • What happens to a participant’s banked credits if they move out of the utility’s service territory? <hr/> <ul style="list-style-type: none"> • At the current bill credit rate, are there circumstances that would create a monetary credit for participants? 	<ul style="list-style-type: none"> • The Subgroup’s initial instinct was that kWh credits for participants who leave the service territory should roll into low income programs, as they do in the case of excess generation. Monetary credits, to the extent a customer receives any, should be paid out. <i>However, the Subgroup ultimately concluded that this question better suited for the Consumer Protection Subgroup.</i> <hr/> <ul style="list-style-type: none"> • Participants may accrue monetary credits to the extent that their bill credit rate minus any subscription fees exceeds the retail rate that they pay for electricity. This issue appears to be limited to the context of commercial and industrial customers whose retail rates are lower than the bill credit rate. <p>The Subgroup agreed to continue to investigate scenarios related to the banking of kWh and monetary credits. Charlie Coggeshall offered to circulate a bill credit calculator that he developed that might assist the Subgroup in exploring the issue.</p>

4. On bill display recommendations

Utilities have different billing systems and will have different abilities to display information on customers’ bills. There was general consensus among the Subgroup that its previous work in identifying types of information that the utilities should include on customers’ bills is appropriate:

Characteristic	Included? Where?	Discussion
Facility Name	Yes, description somewhere	Probably needs to be something descriptive rather than too short
Admin Costs	Yes, separate line	There seemed to be consensus that this should be displayed separately. May be some concern that this adds an extra line. Fixed fee, or a kWh rate x eligible generation
kWh Produced	Yes, credit line/per kWh subscription fee line	Included in credit line with credit rate to show total credit. Also shown in per kWh model for computation of subscription fee
RVOS/Credit Rate	Yes, credit line	Included in credit line to show total credit the differential credit (\$) + (eligible generation (kWh) x bill credit rate (\$))
Per kWh rate	For per kWh customers, subscription fee line	Included in subscription fee line to explain amount.
Lease rate and shares purchased	No	Not important to include breakdown of how subscription fee is calculated if it does not vary throughout the year, and conforms with contracts provided to customers.
Banked kWh	Yes, somewhere	Group thought this value is important to include on bills
Differential Credit Bank	Yes, somewhere	Group thought this value is important to include on bills

5. Next Steps

Members of the Subgroup committed to following up on the following action items:

- Scope of possible alternative subscription models
 - Charlie Coggeshall will discuss alternative subscription models with potential Project Managers and present proposed models and reasons for deviation from the on-bill credit model to the Subgroup and Commission Staff.
- Utility administrative cost recovery (action item from June 13 OPUC workgroup)
 - Utility representatives will develop and present proposed approaches to recover the following administrative costs:
 - Start-up costs
 - Ongoing administrative costs
 - Power (bill credit/PPA) costs
- Program Administrator policy considerations
 - Tee up any policy questions that might arise for Program Administrator
- On-bill credit models
 - Look at utility data exchange flow chart and clean up as necessary

MOORE Caroline

From: Oriana Magnera <oriana@nwenergy.org>
Sent: Monday, July 23, 2018 9:21 AM
To: MOORE Caroline; Jon Miller
Cc: Anderson, Erik; Jaimes Valdez
Subject: Re: UM 1930 Subgroup - Commission status reports
Attachments: Community Solar Consumer Protections Notes.pdf; OPUC Community Solar Consumer Protection Workgroup Topics 7.23.pdf

Attached are the notes from the consumer protections workgroup and a spreadsheet that highlights topics for discussion and how stakeholders are aligning in terms of prioritizing those issues. Below is a summary of our work today.

The consumer protections work group **met one time in July** and in attendance were representatives from **Idaho Power, Pacific Power, Coalition for Community Solar Access (CCSA)/Oregon Solar Energy Industry Association (OSEIA), NW Energy Coalition (NVEC), Spark NW, and NRG Energy**. Additionally, members from the Citizen's Utility Board (CUB), Community Action Partnership of Oregon (CAPO), and Portland General Electric (PGE) have been recruited.

The Commission and CCSA/OSEIA developed lists of **topics for discussion** which were supplemented by group discussion and input from the low-income workgroup: **code of conduct for developers and marketers, standard contract/disclosure language, complaint and dispute resolution procedures, portability** (contract movement within a service territory), **transferability** (shifting a subscription from one site address and customer account to another), **contract provisions and consumer protections specific to subscribers with lower incomes, consumer resources, marketing practices, project manager data** (which may intersect with the project details group), where **consumer protections requirements affect pre-certification** (which may intersect with the project details group), **data privacy** (which may intersect with the utility data exchange group), bill crediting limits and **further understanding of bill credits/excess credits** through a consumer protections lens (which may intersect with the utility data exchange group), specific **protections related to ownership** and ownership/subscription models, and **bill issues** like how on-bill display of information will work (which may intersect with the utility data exchange group).

The workgroup discussed priorities based on importance and timeliness for initial focus. **Industry representatives felt that portability and transferability and the intersection between consumer protections and pre-certification requirements were the issues that might most affect early project development** and require some more immediate clarity. They also noted that there exists **contract and disclosure language in other markets** that we could draw from from an expediency perspective. The **Commission** felt that defining **consumer resources, marketing practices, and data privacy would be most important from a greater program oversight perspective**. Respectively, **utility members and consumer advocates** hope to prioritize **transferability** (and how it would affect building out a billing system), **data privacy and marketing practices**, and **contract and disclosure language** (including the languages in which it is available and how complexly disclosures are written), **marketing practices** (the venues through which potential subscribers receive information), **unique protections for subscribers who are also owners**, and **specific protections for subscribers with lower incomes**.

In addition to contract and disclosure language, the workgroup, through the Commission and NWECA will **look at how programs in other states address these issues and will focus the next, August, meeting** on review of other markets as a baseline for determining what may resonate in Oregon and what may require some creative, and context-specific thinking.

	Community Solar Consumer Protections Issues for Exploration			Other Workgroup Intersections
Code of Conduct	Additional/Sub-Topics	Actions/Next Steps	Available Resources	
Standard Contract/Disclosure Language Complaint and Dispute Resolution Guidelines and Procedures	Contract languages (and use of plain language)	Charlie share standard contract language.	CCSA/Existing market language (look to MD and NY)	
Portability (contract movement within a service territory) Transferability (shifting subscription from one site address and customer account to another)	What happens to a participant's banked (monetary or kWh) credits if they move out of the utility's service territory/terminate subscription?			Low-income
Specific Low-income Protections/Contract Provisions				Low-income
Consumer Resources	Cleaning house for projects?			Project Details
Marketing Practices	How does Commission/PA oversight work? How will people receive information (door to door, mailing, mailers, ?) Marketing languages			Project Details
Project Manager Data				Project Details
Intersection Between Consumer Protections and Pre-Certification Requirements		Kevin share Excel form	Excel subscriber agency form	Utility Data Exchange
Data Privacy				Utility Data Exchange
Bill Crediting Limits/Further Understanding of Bill Credits		Jaimies will look into	On-bill financing models for weatherization	
Ownership models/protections	Bills	How on-bill display of information will work?	On-bill display of information	
Color Code: Issues of Importance/Timeliness				
PUC				
Industry				
Consumer Advocates				
Utilities				

MOORE Caroline

From: Jon Miller <jon@oseia.org>
Sent: Friday, July 20, 2018 4:33 PM
To: MOORE Caroline
Cc: Anderson, Erik; Oriana Magnera; Jaimes Valdez
Subject: Re: UM 1930 Subgroup - Commission status reports
Attachments: AR 603 Project Details subgroup - 2017 meetings summary.eml; Project Details Subgroup July10-2018 Minutes DRAFT.docx; Jun 13_UM 1930 Implementation Reset-Subgroup topics.pdf

Caroline, here's my summary from the PD group:

I have a few possible things to consider with this progress update, outlined below.

1. First, while we met once this year, we also made significant progress last year and it should be included as we move forward and given to the eventual PA. I've attached my final email update on this from last year and I think all the other subgroups delivered a similar update. I'm not sure the commissioners need this now as perhaps they were already briefed on these last December when they were delivered, just want to make sure the information is brought forward.
 1. In addition to the project details sub-group discussions from last year, the PD group held one more meeting on July 9th and has one more scheduled for July 26th.
2. One question was asked at the July 9th PD group meeting about what is the future of these groups? It's a good question and I believe the answer is the PA will take this effort over once they are established. Still including the broader constituency but the PA running the meetings rather than us.
3. I think the PUC's initial subgroup spreadsheet was a good idea. To note things to work on and pass on to the PA, to note discussions to continue, and have things to hold for the PA to work on once they are ready. We talked about potential low hanging fruit items along with thornier issues like interconnection. Both are examples of things we wanted to discuss to prepare the PA and provide them with a running start.
4. With respect to the PD groups progress, our first meeting was interesting. We reconfirmed one important item from last year, that a system impact study or a fully executed interconnection agreement would suffice to meet the interconnection requirement in the rules. However, we ran into a significant conversation around interconnection applications and this brought out a significant conversation on the classification of community solar projects in Oregon. Specifically, are these QF's or not QF's or something in between. There are parties on both sides of the fence - this is a critical issue to clarify as we go forward. In general, here is a synopsis of our first meeting:
 1. The interconnection issues came up because developers were actually going through a process rather than just a thought exercise. This is important and underscores that somethings may not be found out until developers actually go through the process of qualifying systems for the program. The PA should be prepared to deal with these as they come up.
 2. The classifications of these systems is very important and will have specific ramifications. Due to the fact that interconnection is a long lead issue and takes time, this issue should be resolved as soon as possible. Are these projects something other than QF? Or are they QF's? There will be a lively discussion about this in our upcoming meeting on July 26th. See the July 9th meeting notes for more information.

3. Should these systems be Network Resources or should they be Energy Resources? Or should we allow developers to individually choose? Again, this is important and will define the interconnection process they go through.
4. Do we need to develop a new interconnection application and a new interconnection agreement for these systems? We may have to. We will discuss whether we have interconnection processes that will work for community solar (division 82 rules), but I suspect the answer is yes, we have a process, but we until we classify what these systems are (QF or something else, ER or NR), we will not likely be able to finalize an application or agreement.
 1. This also affects systems that want to move from a development asset currently in an interconnection queue over to the community solar program.
5. The PD group agreed to identify around five different project scenarios to try and characterize the issues that could come up and make sure our community solar process is robust. These project scenarios will be discussed at the next meeting on July 26th.
6. The PD group also discussed listing out issues that may be low hanging fruit that we may be able to come to general consensus on.

Attachments:

- final email summary from last year
- PUC spreadsheet on subgroup topics
- draft notes from PD groups July 9th meeting

*****Please use caution when opening links, attachments or responding to this email as it originated outside of PUC.*****

Best,
Jon Miller
Executive Director
Oregon Solar Energy Industries Association - OSEIA
503-701-0792
jon@oseia.org
www.oseia.org

On Jul 16, 2018, at 9:13 AM, MOORE Caroline <caroline.f.moore@state.or.us> wrote:

Hi Subgroup leads,

UM-1930 Project Detail Subgroup Meeting Minutes

July 9, 2018

Members Present: Jon Miller, Kelley Noe (+ 3 others from Idaho Power), Ken Nichols, Rikki Seguin, Lizzie Rubado, Daniel Hale, Caroline Moore, Michael Chestone, Charlie Coggeshall, Michael Cathcart, Lucas Kappel, Erik Anderson, Nate Larsen, Natasha Soares, Clair Carlson, Ryan Sheehy, Sean Micken, Justin Wilson.

Next meeting: TBD, tentatively targeting a day during the last week in July (23rd-27th)

Our discussion started with an intro to the project details group items as proposed in the matrix sent out by PUC staff. Staff made it clear the matrix was a proposal only and the groups should endeavor to identify important issues that should be discussed. At the end of the meeting a request was made for members to submit issues in writing for the group to consider. Several examples are included below.

The primary issue discussed by the group was interconnection issues related to project classification (QF or not a QF, Network Resource vs Energy Resource), interconnection applications and agreements. Members were asked to submit example projects to illustrate issues that could arise. See below for details.

A question was brought up about the work that the Project Details (PD) group is providing. It was reiterated that the PD Group's main purpose is to provide input and clarifications to the Commission and the Commission would make any final formal decisions on rule interpretations. The PD Group is not empowered beyond providing input to the eventual Program Administrator and the Commission.

1. Project pre-certification interconnection requirement discussion

Consensus Item: The group re-confirmed that either a completed system impact study or a completed interconnection agreement would suffice to meet the pre-certification interconnection requirement in the rules (July 29th 2017, order #17 232).

Note the pre-certification section 860-088-00402(d) states "All documentation relevant to the interconnection process as provided in OAR chapter 860, division 82", inferring that additional documentation may be required to fully comply with pre-certification interconnection requirements. However, the consensus that projects with completed system impact studies would be sufficient (with accompanying relevant interconnection documentation) as opposed to only allowing systems with executed interconnection agreements is an important distinction.

2. Project Interconnection classification

The group had a lot of discussion around the appropriate classification of projects and whether they were QF projects, not QF projects, or something in between. This issue will need to be resolved prior to the community solar program moving forward.

Issues discussed included:

- The general classification of the projects as QF or not QF was discussed and no general agreement was reached. It became obvious that this issue is very important to resolve, but also that it may not be easily resolved without Commission involvement.

Even though we may not reach consensus, the group decided to continue the discussion to provide feedback to the Commission to clarify how community solar projects should be classified as this could have major ramifications on interconnection process, cost recovery, project energy re-imburement values, and it's the long lead development task that could stall the program if not defined early.

- Whether projects were Network Resource or Energy Resource was also discussed and no general agreement was reached. This issue is connected to the general classification of the projects and further discussion is required.

Action Item: Create several project scenarios (4-6?) that illustrate distinct and likely project scenarios that capture the most relevant situations and then analyze these scenarios to determine how different classifications might be affected. The goal is to use the scenarios to assist with determining how projects should be classified.

Action Item: Define Network Resource and Energy Resource and their possible application to community solar projects.

Project Scenario Examples (input needed):

A spreadsheet matrix could be developed to compare these scenarios. All systems assumed to be installed on distribution networks. Example below is illustrative only, please provide alternative matrix structure and questions.

	Size	Network	Local Network Capacity?	Transmission required to reach subscribers?	How does QF vs non-QF impact this project?	How does NR vs ER impact this project?	Why is QF or not QF appropriate for this project?	Why is NR or ER appropriate for this project?
Project One	< 360kw	Distribution	> than project	no				
Project Two	< 360kw	Distribution	< than project	yes				
Project Three	> 360kw, <or= 3MW	Distribution	> than project	no				
Project Four	> 360kw, <or= 3MW	Distribution	< than project	yes				
Project Five	> 3MW (wants to transition part to CS program)	Distribution	< than project	yes				

3. Interconnection process, application, and agreement

There appeared to be a general agreement that new applications and agreements may have to be created to capture the community solar program projects. We did not discuss this issue in detail as the previous issue (project classification and ER/NR issues) will likely need to be resolved first.

Action Item: Verify whether there's agreement that new applications and agreements are needed and explore how long this will take and what they will look like (IE are they very similar to the other applications and agreements?). Can this be done prior to defining the project classification?

Action Item: Define the interconnection process / rules for community solar projects. Should we assume only the use of OAR Chapter 860 Division 82 rules? Division 29 rules were brought up in the meeting, however, the July 29th 2017 rules only reference Division 82 rules.

4. Additional items for potential group discussion

Near the end of the meeting several potential additional items to consider were briefly mentioned. The group briefly discussed whether low hanging fruit items that would be easier to reach consensus on

should be brought up first. The group was asked to come up with those items by submitting them to Jon Miller to be added to a list for consideration.

A question about the future of the PD group was brought up. It seems highly likely that when a PA is on board the PD group will handover all material and future meetings will be run by the PA.

Example potential issues/questions provided so far include:

- Section 860-088-0040. Section (4) states the Project Manager may execute contracts with participants for ownership or subscription interests after pre-certification is granted. The assumption is that Project Managers can engage with potential subscribers prior to pre-certification and the only prohibition is executing an ownership or subscription agreement?
- Section 860-088-0070. Co-location requirements need further definition. They reference a 5-mile radius and a 3MW limit or installed in a single municipality or defined urban area. Is there a size limit? What can be co-located?
- Section 860-088-0040. Section (6) states the Project Manager must seek Commission approval of any modification to a pre-certified project. What happens if some event prohibits a project manager that has achieved precertification and enrolled subscribers cannot receive energy from the pre-certified project? For example, a project manager has a PPA with a developer, achieves precertification and begins to enroll subscribers, and an intervening event occurs that prevents the project from coming online (environmental sensitivity, land use issue, bankruptcy, etc). Does the PM keep the pre-certification and find another project or does the pre-certification belong to the project (which would imply that if the project fails, the pre-certification is rescinded)?

Action Item: Group members to submit additional questions or issues that the PD group can consider for future discussions.

Appendix C

OPUC Staff Memo: Community Solar Implementation Update September 18, 2018

ITEM NO. 2

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: September 25, 2018

REGULAR CONSENT EFFECTIVE DATE _____ N/A _____

DATE: September 18, 2018

TO: Public Utility Commission

FROM: Caroline Moore *CM*

THROUGH: Jason Eisdorfer *JE* and JP Batmale *JB*

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. UM 1930) Community Solar Implementation Update.
Information only.

STAFF RECOMMENDATION:

Informational filing - no recommendation.

DISCUSSION:

Issue

This report provides an update on two key Community Solar Program (CSP) implementation milestones:

1. The competitive selection of the CSP Program Administrator (PA); and
2. The establishment of the process by which utilities will recover program start-up costs.

Applicable Law

Community Solar Program Administrator

Section 22 of Senate Bill (SB) 1547, effective March 8, 2016 and codified in Oregon Revised Statute (ORS) 757.386, directs the Public Utility Commission of Oregon (Commission) to establish a community solar program (hereinafter referred to as "Community Solar Program", "Program", or "CSP").

Division 88 of Chapter 860 of the Administrative Rules specifies that the Commission will select a CSP Program Administrator (PA) through a competitive bidding process.¹ OAR 860-088-0020 outlines the PA's responsibility to support the Commission's implementation and ongoing management of the CSP, which includes:

- Developing the Program Implementation Manual (PIM) in collaboration with Commission Staff;
- Facilitating the multi-step process for the Commission to certify projects for participation in the program;
- Facilitating the calculation and exchange of large amounts of data and monies between utilities, Project Managers, and CSP participants;
- Coordinating with the Low-Income Facilitator (LIF) to meet the CSP's low-income requirements; and
- Supporting the Commission and utilities in implementing the consumer protection requirements set forth in the CSP rules.

Competitive Procurement

Oregon Administrative Rules (OAR) Chapter 125, Division 246 delegate procurement authority to the Department of Administrative Services (DAS) for procurements exceeding \$150,000. ORS 279B.060 and OAR 125-247-0260 set forth the methods for competitive sealed proposals. A combination of these methods is deployed in the process to procure CSP Program Administrator services.

CSP Cost Recovery

ORS 757.386(7) specifies different treatment for the start-up and ongoing costs of the CSP.

1. Start-up costs: Utilities may recover prudently-incurred program start-up costs as well as costs of energy purchased from CSP projects (Projects) from all ratepayers.
2. Ongoing costs: Owners and subscribers (i.e., program participants) bear the cost to construct and operate Projects, plus ongoing program administration costs.

OAR 860-088-0160(1) clarifies that start-up PA and LIF costs are recoverable in rates of all ratepayers. Further, the rules specify that utilities' prudently-incurred start-up costs recoverable from ratepayers include, but are not limited to, costs associated with customer account information transfer and on-bill crediting and payment, but exclude any costs associated with the electric company developing a project.²

¹ OAR 860-088-0020(1).

² OAR 860-088-0160(1)(b).

OAR 860-088-0160(2) clarifies that ongoing PA and LIF costs are collected from CSP participants.³

Analysis

PA Selection Background

Acting on behalf of the Commission, DAS released the Request for Proposal (RFP) for PA services on April 16, 2018.⁴ The RFP closed on May 31, 2018, and DAS received five proposals. The evaluation team scored proposals based on criteria set forth in the RFP and described in the Selection Methods section of this report. On July 25, 2018, DAS released Addendum #1 to the RFP. The addendum provided the following modifications to the RFP process:⁵

- Established a competitive range in the initial scoring of proposals, whereby DAS identified a natural break between the three highest-scoring proposers and the two lowest-scoring proposers.
- Announced the three highest-scoring proposers would move forward to a round of interviews.
- Estimated issuance of the Notice of Intent to Award a Contract following the interviews, by October 12, 2018.

At the July 31, 2018 Public Meeting, DAS updated the Commission on the status of the RFP on behalf of Staff. Following the update, Staff committed to notify the Commission at a public meeting when the Notice of Intent to Award a Contract is issued. On August 24, 2018, DAS issued the Notice of Intent to Award a Contract to Energy Solutions. This report is intended to provide notice to the Commission that this important implementation milestone is complete.

PA Selection Methods

The RFP and Addendum #1 outline the methods that led to the selection of Energy Solutions. Staff worked closely with DAS to ensure that the selection process aligned with the Commission's needs in administering a successful program. Proposals were evaluated based on criteria outlined in Section 4.10.2 of the RFP, including the proposers':

- Understanding of the timelines and milestones required to implement the program thoroughly and efficiently, including the approach to start-up and ongoing tasks and understanding of anticipated implementation challenges.
- Approach to CSP cost recovery, including the ability to minimize cost shifting to non-participants and prevent participants from undue financial hardship. This

³ The program rules do not specify recovery for utilities' ongoing costs.

⁴ DASPS-2250-17 –Third Party Community Solar Administrator Request for Proposal (RFP).

⁵ DASPS-2250-17 –Third Party Community Solar Administrator.

included consideration for the clarity of cost elements and designation of start-up versus ongoing costs.

- Demonstrated experience and approach to managing large, complex programs.
- Demonstrated ability to handle substantial monthly transactions between multiple entities including detailed financial settlements and secure customer data. This included consideration of the software and other tools proposed to perform the PA services.
- Approach to facilitating the CSP's low-income elements, including outreach and LIF management.
- Approach to stakeholder engagement and the resolution of policy questions with multiple stakeholders.
- Demonstrated ability to identify and manage conflict of interest.

PA Selection Next Steps

The RFP is currently in the contract negotiation phase. DAS remains the single point of contact for the RFP during contract negotiations.

Staff looks forward to engaging in the next phase of the RFP process with Energy Solutions and DAS. Because this is a new and unique scope of services, the timeline to complete contract negotiations is unknown. Informal guidance from DAS and stakeholders suggests that this process may take 60 – 90 days. While Staff is taking steps to ensure an expedient process, it continues to focus its efforts on three key intentions:

- Ensuring the complete and timely delivery of these complex services,
- Transparency of process; and
- Securing the best value for ratepayers.

When contract negotiations are complete, Staff will bring the contract to the Commission for approval. If contract negotiations are not complete within 60 days, Staff will provide a timing update to the Commission at a public meeting.

Cost Recovery Background

CSP costs can be categorized as follows:

- Start-up costs
 - PA/LIF start-up costs – recoverable from all ratepayers
 - Utility start-up costs – prudently incurred costs recoverable from all ratepayers
- Ongoing costs
 - PA/LIF ongoing costs – recoverable from program participants
 - Utility ongoing costs – recovery unspecified

- Bill credit and unsubscribed energy costs – recoverable from all ratepayers
- Project Manager costs (costs to construct and operate a utility or third-party Project) – recoverable from Project participants

Utilities, stakeholders, and Staff began outlining the process to recover CSP costs at the June 13, 2018 workshop. Participants agreed that program start-up costs should be addressed first, because these costs are the most immediate costs to be incurred. The utilities committed to developing brief proposals for start-up cost recovery that included the following:

- The mechanism by which each utility will recover PA/LIF start-up costs;
- The mechanism by which each utility will recover prudently-incurred utility start-up costs; and
- The allocation of PA/LIF start-up costs across utilities.

Idaho Power Company (IPC), Portland General Electric (PGE), and PacifiCorp (PAC) submitted CSP cost recovery proposals to Staff on August 13, 2018. Staff circulated the proposals to the UM 1930 service list on August 15, 2018. Parties submitted comments on the cost recovery proposals on September 7, 2018.⁶

Utility Proposals for Start-up Costs

PAC and PGE propose recovery of both the PA/LIF and utility start-up costs with an automatic adjustment clause. The utilities would each file a tariff to recover forecasted start-up costs (PA/LIF and utility) and would also apply to defer any variance between actual and forecasted start-up costs. Each year that start-up costs are incurred, PAC and PGE would request to update the tariff to take into account an updated forecast of start-up costs and also, to recover or refund the deferred variance between forecasted and actual costs from the preceding deferral period. PAC further noted that their start-up costs will include capital expenses and that it intends to seek recovery of these costs in the automatic adjustment clause.⁷

IPC proposes to defer all start-up costs and begin recovery in rates after the start-up period is ended.

⁶ At the July 31, 2018 Public meeting, Staff committed to keep the Commission informed as to the status of administrative cost recovery issues, and communicated its plan to provide an update at a Public Meeting on August 31, 2018. Due to the timing of the proposals and Staff and Stakeholder's review, Staff submits its cost recovery update in this report.

⁷ These costs will be associated with billing and IT system upgrades.

All three utilities suggest dividing the PA and LIF start-up costs based on average customer counts as listed in the 2016 Oregon Statistics Book, which provides the following allocation of start-up costs:

- PGE – 59.2%,
- PAC – 39.5%, and
- IPC – 1.3%.

While not asked to do so, all three utilities propose a mechanism to recover ongoing costs. The utilities' propose similar recovery for ongoing PA/LIF and ongoing utility costs as proposed for recovery of start-up administrative costs.

With regard to bill credits and the purchase of unsubscribed power, all three utilities propose to include these costs of in their Net Variable Power Cost (NVPC) recovery mechanisms. The three utilities propose that these amounts not be subject to the deadbands, sharings, and earnings test applied in those mechanisms and instead, propose that these amounts be subject to 100 percent recovery.

The utility proposals are provided in Attachments A - C.

Stakeholder Feedback

The Oregon Citizens' Utility Board (CUB), Oregon Solar Energy Industries Association (OSEIA) and the Coalition for Community Solar Access circulated feedback regarding the utilities' cost recovery proposals. OSEIA and the Coalition for Community Solar Access submitted jointly as "Solar Parties."

CUB supports the utilities' proposed allocation of PA/LIF start-up costs based on average customer count, and the use of an automatic adjustment mechanism to provide contemporaneous recovery of the PA/LIF start-up costs. However, CUB has concerns that contemporaneous recovery of utility start-up costs will not provide an adequate incentive for utilities to control costs or provide adequate opportunity to review the costs for prudence. CUB also notes that recovery of capital investment in deferrals is an outstanding issue. Further, CUB notes that the utilities have been making upgrades to their billing and IT systems since SB 1547 was adopted almost two and one-half years ago, and it intends to scrutinize any incremental capital investments needed for the CSP very carefully.

With respect to the utilities' proposals regarding ongoing costs, CUB notes that Staff asked the utilities for proposals regarding recovery of start-up costs only. However, CUB comments that a clear delineation between the start-up and ongoing costs is important and supports PAC's proposal to work with the PA and stakeholders to

establish a stream of recovery for ongoing costs. With respect to recovery of bill credits, CUB opposes the proposal to recover 100 percent of these costs through the utilities' power cost mechanisms without being subject to the sharing to the mechanisms' deadbands, sharing, and earnings tests. CUB believes that these mechanisms provide an incentive for utilities to control costs.

The Solar Parties provide suggestions for the classification of start-up and ongoing costs, the display of costs on ratepayers' bills, and considerations for measuring rate impacts of CSP bill credits. Further, the Solar Parties note the importance of balancing transparency with expediency.

The Solar Parties note that the distinction between start-up and ongoing costs is not fully defined and make suggestions regarding the distinction between the two. First the Solar Parties suggest the utilities' administrative costs could be properly classified as start-up costs under OAR 860-088-0160, no matter when they are incurred. The Solar Parties suggest that categorizing the utilities' administrative costs incurred after the end of the start-up period would be one way in which to decrease the cost of participation in the CSP.

The Solar Parties also suggest that the Commission consider the period necessary to fill 25 percent of the initial capacity tier as the start-up phase of the CSP. The Solar Parties recommend that the calculation of any ongoing administrative costs be established on an expectation that the entire initial capacity tier of the program (at least) is certified and operating so as to not penalize the first-mover participants with higher administrative fees. And, any administrative fees imposed on program participants should never increase after pre-certification.

Finally, the Solar Parties note that if the administrative costs of the CSP are displayed on ratepayers' bills, the manner in which they are displayed is important.

With respect to recovery of bill credits, the Solar Parties recommend that when determining the rate impact of bill credits under the CSP, the impact should be measured by the difference between the RVOS and the bill credit rate rather than the entire amount of the bill credit.

Staff Feedback on Start-up Cost Recovery

Staff appreciates the utilities' willingness to submit draft proposals for recovery of the CSP start-up costs. Review of the utilities' proposals and CUB's feedback suggests that capital and non-capital costs and utility start-up costs should be considered separately. Therefore, Staff offers the following initial feedback for three types of start-up cost described in the utilities' proposals:

1. PA/LIF Start-up Costs

Staff supports a cost-recovery mechanism that allows for contemporaneous recovery of PA/LIF start-up costs. Staff finds that the PA/LIF costs are discrete and required to facilitate a program mandated by the legislature. Further, these costs are governed by the contract between the PA and the Commission. It is not the utilities' responsibility to bear the risk of variation in PA/LIF costs.

Accordingly, Staff supports PGE's and PAC's proposal to recover these costs with a forward-and-backward looking automatic adjustment clause. For the period in which start-up costs are incurred, this will allow the utilities to update the tariff annually to take into account an updated forecast of PA/LIF start-up costs and to defer and recover or refund any variance between forecasted and actual costs.

Staff also supports IPC's proposal to defer PA/LIF start-up costs until the end of the start-up period and begin recovery of the deferred amounts when the start-up period is finished. IPC's share of the costs of the PA and LIF is relatively small and does not necessarily warrant the cost and inconvenience of changing customer rates annually to recover. Staff notes that the deferred amounts will earn interest at IPC's authorized rate of return (AROR). However, this does not outweigh the cost and inconvenience of annual rate changes for the relatively small amounts at issue.

2. Utility Start-up Costs – Non-Capital

Staff agrees with CUB that the utilities' start-up costs require thorough scrutiny to ensure that only incremental, prudently incurred costs are recovered from ratepayers through the automatic adjustment clause. Further, Staff notes that the utility start-up costs carry substantial uncertainty as this is a complex and unique program. These costs may be challenging for PAC and PGE to accurately forecast and for stakeholders and Staff to review for prudence in advance. At the same time, Staff recognizes that these costs are required to facilitate a program mandated by the legislature and the utilities are entitled to a certain degree of certainty that they can recover their prudently incurred costs. Accordingly, Staff proposes a workshop between Staff, stakeholders, PGE, and PacifiCorp to allow the opportunity to come to agreement about the recovery of the utilities' start-up costs.

Staff supports IPC's proposal to defer utility start-up costs until the end of the start-up period.

3. Utility Start-up Costs – Capital

Similar to CUB, Staff is not able to support PAC's proposal to defer recovery of and on capital investment for later amortization in rates. Additional consideration is required to determine the appropriate method of recovery for capital investment associated with the CSP. This includes an understanding of the type and magnitude of capital investments that may be required, and whether PGE and IPC will propose capital utility start-up costs. Staff intends to discuss this matter at the workshop on utility start-up cost recovery.

Finally, Staff appreciates the Solar Parties' identification of important questions related to start-up and ongoing cost recovery. Staff will work with the PA and stakeholders to ensure these considerations are included throughout the implementation phase. In particular, Staff agrees that cost recovery decisions rely on a detailed understanding of how start-up and ongoing cost will be delineated.

Staff Feedback on the Allocation of Start-up Costs

Staff appreciates the utilities' efforts to reach consensus on the allocation of the costs of the PA and LIF. However, Staff is considering whether system peak is a better reflection of the utilities' share of costs. Because the system peak determines the amount of projects that can be available to ratepayers of each utilities in both the initial capacity tier and the overall capacity tier, it may be a better reflection of the administrative costs associated with each utilities' ratepayers.

Both methods produce similar allocations. But, it is important that the underlying rationale of the allocation methodology be sound. Staff will include this issue in the utility start-up cost recovery workshop.

Utility	Share based on average customer count	Share based on 2016 System Peak
PGE	59.2%	57.8%
PAC	39.5%	40.1%
IPC	1.3%	2.0%

Staff Feedback on Ongoing Costs

Staff appreciates the utilities' transparency regarding proposals for recovery of ongoing costs, including ongoing administrative costs, bill credits, and unsubscribed energy costs. However, the start-up costs are the costs at issue in the near-term. There will not be enough certainty around the designation, allocation, and amortization of ongoing

costs to provide meaningful observation until the PA contract is in place.⁸ Similarly, Staff believes it is not necessary to resolve any issues related to bill credits prior to the time the PA is on board.

Next Steps

IPC has already filed an application to defer start-up costs associated with the CSP. PAC and PGE have both proposed to file applications to defer start-up costs. Staff suggests that PGE and PAC file applications as soon as possible.

In addition, the utilities, stakeholders, and Staff should continue to work together to resolve start-up cost recovery issues by the end of November. Workshop topics may include:

- What type and magnitude of capital and non-capital utility start-up costs are anticipated;
- What is the appropriate method of recovery for capital and non-capital utility start-up costs;
- How should PA/LIF start-up costs be allocated across the utilities; and
- What should the PA consider when finalizing its detailed proposal to delineate start-up and ongoing costs in detail?

After the PA/LIF costs are known and parties conclude efforts to resolve the outstanding issues listed above, PGE and PAC should prepare to file an Advice Filing. If consensus is not reached prior to the time the utilities file the tariffs, stakeholders and Staff can address any concerns in the process for those filings.

After the PA is onboard and there is more information regarding the nature of the ongoing costs, Staff will work with the utilities, the PA, and stakeholders to address utility proposals to recover ongoing costs.

Staff proposes to provide an update on these efforts to the Commission by the end of November.

Conclusion

PA Selection

DAS has issued the notice of intent to award for the PA, identifying Energy Solutions as the selected proposer. Staff is looking forward to working with DAS and Energy

⁸ For example, it is unknown whether ongoing costs will be recovered per participant, per kW, per kWh and whether additional mechanisms, such as project application fees, will cover a portion of ongoing costs.

Solutions in the contracting phase and will continue to provide updates to the Commission.

Cost Recovery

The utilities provided thoughtful proposals for CSP start-up and ongoing cost recovery. In addition, CUB and the Solar Parties provided valuable feedback on the utilities' proposals.

To continue progress on cost recovery activities, Staff proposes the following next steps:

- PAC and PGE file applications to defer start-up costs as soon as possible.
- All three utilities will work with stakeholders and Staff to resolve remaining issues related to utility start-up cost recovery by the end of November 2018.
- PAC and PGE will file tariffs when PA/LIF start-up costs are known and efforts to resolve outstanding utility start-up costs recovery issues conclude.
- Staff will work with the PA, utilities, and stakeholders to establish ongoing cost recovery after the PA is onboard. Further, stakeholders and Staff will work with the PA to consider the Solar Parties' suggestions related to the distinction, measurement, and communication of various CSP costs.
- Staff will continue to update the Commission on the status of cost recovery efforts, including a status update no later than November 2018.

PROPOSED COMMISSION MOTION:

Informational filing - no recommendation.

UM 1930 Update

Idaho Power Company – Oregon Community Solar Cost Recovery

Deferral of Start-Up Costs:

In August 2016, Idaho Power filed a deferral for start-up costs for the Oregon community solar program under Docket UM 1795. The Company requested re-authorization of that deferral in March 2018. Start-up costs include costs that the utility will incur to implement the program as well as funding for the third-party administrator.

- Utility start-up costs
 - Legal/Professional and Consultant Fees
 - Modification of IT Systems
 - Other – unidentified costs that may be incurred to develop CS program

- Third-Party Administrator Funding – start-up costs

Idaho Power recommends that all start-up costs internal and external (Program Administrator funding) continue to be deferred per the authorized deferral in UM 1795 until those costs are recovered in rates.

Allocation of Third-Party Administrator Start-Up Costs

Idaho Power, PacifiCorp, and Portland General Electric recommend allocating Third-party administrator start-up costs based on the 2016 Oregon average customer counts. Using customer count from the 2016 Oregon Utility Statistics book the allocation would be IPC – 1.3%, PAC – 39.5%, and PGE – 59.2%.

Recovery of Start-Up Costs

Idaho Power's recommendation is to request amortization and collection in rates of the deferred start-up costs at the point when the start-up period has ended and on-going costs will be borne by community solar participants. In a similar fashion that amortization of deferred intervenor funding is collected through Idaho Power's Oregon Schedule 56, Power Cost Adjustment Mechanism, Idaho Power recommends that amortization of the deferred start-up costs be collected through Schedule 56 and not be subject to deadbands.

Ongoing Internal Administrative Costs

Idaho Power plans to file a deferral with a balancing account to track ongoing internal administrative costs of the Program. These costs will be recovered from the community solar program participants. Idaho Power envisions that the rate(s) established to recover the internal ongoing administrative costs will be part of the community solar program tariff.

Recovery of Bill Credits and PPA costs

The bill credits paid to customers and the PPA costs should be included in Idaho Power's Annual Power Cost Update (APCU) as purchased power expenses which would be 100% directly assigned to Idaho Power's Oregon jurisdiction.



Portland General Electric
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August 13, 2018

Via email: Caroline.Moore@State.Or.Us

Public Utility Commission of Oregon
Attn: Caroline Moore
201 High St. SE, Suite 100
P.O. Box 1088
Salem OR 97308-1088

RE: Portland General Electric's (PGE) Proposed Community Solar Cost Recovery Plan

Per Oregon Administrative Rule (OAR) 860-088-0160 – regarding Community Solar Program Funding – electric companies will recover start-up costs incurred during the development or modification of the Community Solar Program through electric company rates. The rules define start-up costs as:

- 1) Costs associated with the Program Administrator and Low-Income Facilitator; and
- 2) Each electric company's prudently-incurred start-up costs associated with implementing the Community Solar Program. These costs include, but are not limited to, costs associated with customer account information transfer and on-bill crediting and payment, but exclude any costs associated with the electric company developing a project.

To recover these start-up costs, PGE proposes to file for deferred accounting, as well as to use an accompanying automatic adjustment clause and balancing account to track the ongoing cost and recovery amounts for the start-up costs of the Community Solar Program. The use of an automatic adjustment clause will allow recovery of start-up costs to begin as soon as the cost data is approved by the Commission. A balancing account will provide the ability to track and true-up the amounts associated with Community Solar Program start-up. PGE proposes either the use of Schedule 105 – Regulatory Adjustments – or the filing of a new rider specific to the recovery of Community Solar start-up costs.

In addition to start-up costs, OAR 860-088-0160 also instructs the recovery of ongoing costs associated with the program administrator and low-income facilitator to be collected from participants. PGE similarly proposes the filing of a deferred accounting mechanism, as well as the use of an automatic adjustment clause paired with a balancing account to provide the ability to true-up recovery amounts.



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Allocation proposed

As the Community Solar Program is statewide, the start-up costs relating to the Program Administrator and Low Income Facilitator should be allocated between the State’s three investor-owned utilities. PGE proposes to allocate the costs of this statewide program in accordance with average customer counts – as listed in the 2016 Oregon Statistics Book. The allocated percentages would be as follows:

- PGE – 59.2% of statewide start-up costs (859,396 customers)
- PacifiCorp – 39.5% (574,131 customers)
- Idaho Power – 1.3% (18,848 customers)

Bill Credits

Per the Commission’s order, the Community Solar Program will provide bill credits to subscribing customers at the retail rate for the first 40MW of program development, with a credit rate after the first 40MW of development to be determined. To recover the cost of bill credits, PGE proposes to include the bill credit amounts into PGE’s Annual Update Tariff (AUT) filing, which would then be recovered through Schedule 125 – Annual Power Cost Update. PGE recommends that these bill credit costs not be subject to deadbands. This recovery mechanism would be applicable to all cost-of-service bills for electricity service served under the following schedules: 7, 15, 32, 38, 47, 49, 75, 83, 85, 89, 90, 91, 92, and 95.

Table 1 below is intended to summarize PGE’s proposals in this memo:

Recovery	Proposed treatment	Proposed Recovery Schedule
Start-up costs	Deferred accounting, with automatic adjustment clause and balancing account	Schedule 105, or initiation of new schedule specific to community solar
Ongoing Costs	Deferred accounting, with automatic adjustment clause and balancing account	Schedule 105, or initiation of new schedule specific to community solar
Bill credits	Inclusion in PGE’s AUT, credit amount not subject to deadbands	Schedule 125 – Annual Power Cost Update

Table 1 – PGE cost recovery proposals for Community Solar Start-up

**PacifiCorp Regulatory Affairs
Community Solar Cost Recovery Plan
Provided to Staff August 13, 2018**

This document summarizes PacifiCorp’s regulatory plan for cost recovery of PacifiCorp’s costs related to the Oregon Community Solar program.

Costs expected for establishing Oregon Community Solar Program

Costs categories have been identified as follows. Note that both start-up costs and on-going costs exclude any costs associated with PacifiCorp developing its own community solar project. If PacifiCorp develops its own community solar project, those costs will be separate from the costs described below and are only recoverable from the participants in that project.

Oregon Community Solar Program – PacifiCorp Cost Recovery Summary

Cost category	Description	How recovered
Start-up costs	Costs associated with developing the facilitation of the community solar program including: <ul style="list-style-type: none"> • Program administrator • Low income facilitator • PacifiCorp’s incremental costs of implementing community solar programs (customer account data transfer, on-bill crediting and payment, etc.) 	Recovered from all customers through a separate tariff rider
On-going costs	<ul style="list-style-type: none"> • Program administrator • Low income facilitator • PacifiCorp’s incremental costs of maintaining availability of community solar programs for customers 	Recovered from community solar program participants through a separate tariff rider (and separate from the start-up costs tariff rider)
Participants’ bill credits and unsubscribed energy Power Purchase Agreement costs	PacifiCorp’s costs for: <ul style="list-style-type: none"> • Bill credit to participants at a fixed rate for 20 years • Purchase of unsubscribed energy from projects at “as available” avoided cost rates 	Recovered from all customers through net power costs set in the Transition Adjustment Mechanism (TAM); any 2019 costs will be deferred for later inclusion in the start-up costs tariff rider.

Allocation of Costs Associated with Program Administrator and Low Income Facilitator
PacifiCorp, Portland General Electric Company and Idaho Power Company propose to allocate these costs on the basis of 2016 Oregon average customer counts.

	Average Customers	
	Amount	Percentage
Idaho Power	18,848	1.30%
PacifiCorp	574,131	39.53%
PGE	859,396	59.17%
	1,452,375	
source: 2016 Oregon statistics book		

PacifiCorp Cost Recovery Required Filings

Start-up costs

Cost recovery of start-up costs will be achieved through a cost-of-service automatic adjustment clause to allow recovery of projected costs along with a balancing account to track over- and under- collections of actual costs. Required filings will include an application for deferred accounting to approve the use of a balancing account for the costs of start-up of the community solar program and collections associated with start-up costs and a tariff advice filing to implement a new rate schedule to collect these costs from all customers. PacifiCorp highlights the fact that its start-up costs will include capital projects, for which PacifiCorp will seek recovery of return on and return of in rates, which will be recorded in the proposed balancing account.

On-going costs

At some point in time as determined by the program administrator and stakeholders, a separate stream of cost recovery for on-going costs will be established. Recovery of these costs will be similar as to that for start-up costs, through a cost-of-service automatic adjustment clause to allow recovery of projected costs along with a balancing account to track over- and under-collections of actual costs. Required filings will include an application for deferred accounting to approve the use of a balancing account for the costs for on-going community solar program maintenance and collections associated with on-going costs and a tariff advice filing to implement a new rate schedule to collect these costs from community solar program participants.

Participant bill credits and unsubscribed energy costs

PacifiCorp is obligated to credit community solar participants at a fixed rate for 20 years and purchase unsubscribed energy from community solar project managers at “as available” avoided cost rates. Recovery of these costs will be set annually through the TAM as part of net power costs. The cost associated with bill credits will be situs-assigned to Oregon to be collected from all Oregon customers. Recovery of unsubscribed energy costs at avoided cost rates will be system-allocated to be collected from all customers.

PacifiCorp emphasizes that variances in actual and forecasted TAM amounts should be tracked separately and should not be subject to the deadbands and earnings test of the power cost

adjustment mechanism. Note that recovery of these costs for 2019 will need to be achieved through a separate deferral.

Next step

- File deferred accounting application to support the balancing account that will track variances related to start-up cost actuals and tariff rider collections. This filing can be targeted for late August/early September.

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
UM 1930**

In the Matter of)	
)	
PUBLIC UTILITY COMMISSION OF)	
OREGON,)	COMMENTS OF THE
)	OREGON CITIZENS' UTILITY
Community Solar Program Implementation.)	BOARD
_____)	

I. INTRODUCTION

The Oregon Citizens' Utility Board (CUB) provides these comments on the preliminary cost recovery proposals circulated by Portland General Electric (PGE), PacifiCorp (PAC), and Idaho Power Company (IPCO) in the above-captioned proceeding. CUB appreciates the opportunity to provide written comments at the request of an August 24, 2018 email by Oregon Public Utility Commission Staff (Staff). CUB realizes the community solar program was mandated by SB 1547 and that certain costs are provided recovery in OAR 860-088-0160. Therefore, we understand the utilities' need to come up with creative mechanisms to recoup community solar-related costs. However, we do have some concerns with the utilities' proposals as circulated. CUB's comments will examine the utilities' proposed treatment of start-up costs and ongoing costs before detailing any remaining concerns.

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II. START-UP COSTS

As PGE correctly details, OAR 860-088-0160(1) provides for the recovery of: (a) costs associated with the Program Administrator and Low-Income Facilitator; and (b) prudently incurred costs associated with implementation including customer account information transfer and on-bill crediting and payment, but exclude any costs associated with the development of a project. All utilities propose using deferred accounting to track these costs for later amortization into rates. Additionally, both PGE and PAC propose utilizing a cost-of-service automatic adjustment clause and an accompanying balancing account to begin recovery of these costs immediately and track and true-up costs as the programs are implemented.

A. Capital Expenditures

PAC explicitly notes that its start-up costs will include capital projects for which it will seek a return *on* and a return *of* its investment. CUB assumes that PGE and IPCO will also seek cost recovery for capital additions to their IT and billing systems. This presents a couple issues. First, SB 1547 was passed in 2016, and the utilities have now had approximately two and a half years to plan for the rollout of community solar programs and the attendant necessary expenditures. In the meantime, the utilities have been outlaying capital to upgrade their billing and IT systems. PGE specifically rolled out its new CIS system in Q2 of 2018. In short, the utilities should have seen this coming, and upgrades to their systems needed to administer the community solar program should have already occurred. To the extent the utilities believe that new capital additions are necessary, CUB believes there needs to be adequate opportunity to conduct a necessary prudence review, as OAR 860-088-0160(1)(b) dictates. Even non-capital start-up costs must be subject to the same stringent review. Specifically for capital additions,

CUB believes the utilities need to offer concrete, detailed explanations of why these costs are required.

Second, whether the Commission has the requisite authority to approve a deferral for capital expenditures (*i.e.*, whether it is legal or should be allowed from a policy perspective) remains an outstanding issue. That issue was fully litigated in Docket No. UM 1909, and currently awaits Commission decision.¹ Traditional ratemaking principles dictate that capital expenditures are, and have always been, properly brought forth for recovery in a general rate case proceeding and subject to regulatory lag. The utilities' proposals to defer the capital costs associated with community solar investment may be barred pending the outcome of this decision. The continued trend to seek to defer capital costs in Oregon threatens to erode the bedrock principles of ratemaking, and the utilities' proposals in this proceeding are no different.

B. Allocation Proposal

CUB is supportive of the utilities' proposals to allocate start-up costs associated with the co-utilized Program Administrator and Low Income Facilitator on the basis of 2016 Oregon average customer counts. Similarly, CUB believes it is reasonable to spread start-up costs amongst all ratepayers, rather than only to program participants. While the program is in its infancy, it is appropriate to utilize costs from a broad range of utility customers to get it off the ground.

III. ONGOING COSTS

CUB supports the utilities proposal to recover ongoing costs only from community solar program participants. This aligns with general ratemaking principles of cost causation. CUB notes that the email from Staff described the utilities' proposals as only their treatment of *start-*

¹ See *in re Public Utility Commission of Oregon Investigation of the Scope of the Commission's Authority to Defer Capital Costs*, OPUC Docket No. UM 1909.

up costs. While it is important to detail proposals of how ongoing costs should be recovered as well, CUB believes that a clear delineation be outlined regarding what constitutes a start-up vs. an ongoing cost. This will help ensure that only community solar participants are levied with ongoing costs. CUB supports PAC's proposal to work with the program administrator and stakeholders to establish a stream of recovery for ongoing costs. This will ensure adequate stakeholder review.

IV. GENERAL CONCERNS

A. *Use of a Balancing Account*

As discussed, CUB recognizes that the community solar program was mandated by the legislature, and provisions in the administrative rules provide cost recovery to the utilities. However, the use of a balancing account to provide dollar for dollar recovery to the utilities has the potential to detract from stakeholders' and the Commission's ability to conduct an adequate prudence review as required by OAR 860-088-0160(1)(b). When a deferred accounting application is reviewed for later amortization in rates, stakeholders have at least some opportunity to review costs for prudence. From CUB's experience, balancing accounts are often established in manner which allows costs to be passed through to customers without adequate review. In addition, guaranteed dollar-for-dollar recovery from a balancing account removes any incentive for the utility to control its costs. CUB generally supports allowing utilities to forecast the expected cost of this program into rates as is done with most other necessary costs. CUB believes that the use of a balancing account should not be allowed in the context of community solar program cost recovery.

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B. *PAC's Proposal to Forecast Participant Bill Credits and Unsubscribed Energy Costs in its Transition Adjustment Mechanism (TAM)*

PAC proposes to annually forecast the costs associated with program participant bill credits and the purchase of unsubscribed energy costs annually through its TAM. The TAM is PAC's annual proceeding in which it forecasts net variable power costs. The variance between forecasted and actual power costs is then trued up through its annual power cost adjustment mechanism (PCAM). However, the PCAM contains an asymmetrical deadband, and, if the difference between forecasted and actuals falls within that deadband, PAC cannot recover the relative shortage and customers cannot recover the relative benefit. Here, PAC is proposing to remove these community solar forecasted costs from being analyzed in the PCAM. This means that, regardless of any minor variances between forecasted and actual costs, PAC will receive total recovery of these costs. CUB opposes this fundamental change for a couple reasons.

First, it unnecessarily complicates both the TAM and the PCAM in a way that undermines how the two mechanisms interact. Containing a portion of forecasted costs that are subject to a deadband and a portion of costs that are not subject to a deadband has the potential to set a poor precedent that demonstrates that other forecasted costs may also not be subject to the deadband. Second, it detracts from PAC's incentive to control costs in a forecasted year. The TAM is forecasted *annually*. Therefore, PAC is not taking on a significant risk due to year-to-year variances (*i.e.*, it is not forecasted a cost that it is then stuck with for several years). The goal of the TAM is to set as accurate forecasted costs as possible. PAC should have to retain the incentive to control costs and set an accurate a forecast as possible.

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Signed this 7th of September, 2018.

Attachment D
Page 7 of 7



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RE: Comments on Utility Cost Recovery Proposals

The Oregon Solar Energy Industries Association and Coalition for Community Solar Access (Solar Parties) offer these comments in response to the utility cost recovery proposals submitted to the Public Utility Commission (PUC) Staff. We appreciate the opportunity to provide this feedback. Our comments and recommendations are captured in the following four bullet points.

- **Balancing transparency with expediency.** Any costs the utilities are attributing to the community solar program (start-up and ongoing) should be fully transparent to the PUC, in particular to avoid those funds supporting other programs or utility functions without adequate tracking and accounting. The Solar Parties defer to the Citizens Utility Board (CUB) with regards to the best practices associated with cost recovery. However, we also note that due diligence in this area should be balanced with enabling and empowering the utilities to establish the program infrastructure, as needed, in a timely manner that will not delay the program launch or operability.

From the customer's perspective, the Solar Parties would also emphasize the importance of displaying administrative costs – if appropriate - in as simple a manner as possible, and to be sensitive to what participants and non-participants would be viewing on their bills. This topic has been discussed at some level in the Utility Data Exchange Subgroup (see notes submitted to the PUC Staff on Dec. 29, 2017 as well as meeting notes from the July 9 meeting regarding participant bill display), though there has not been consideration regarding how – if at all – the start-up costs for the program would be reflected on all rate payer bills.

- **Defining utility administrative “start-up” vs. “ongoing” costs.** There remains an important outstanding question relating to whether “ongoing” utility administrative costs (not associated with the Program Administrator) are recoverable through rates or should be recovered through participants. The legislation is clear in suggesting that “start-up” costs are recoverable through rates and “ongoing” costs are recoverable through participants¹, however it gives the PUC discretion to define those two terms. Consequently, 860-088-0160 defines “start-up” costs as costs associated with the Program Administrator and Low-Income Facilitator, and “*Each electric company’s prudently-incurred start-up costs associated with implementing the Community Solar Program. These costs include, but are not limited to, costs associated with customer account information transfer and on-bill crediting and payment, but exclude any costs associated with the electric company developing a project.*”² Conversely, “ongoing” costs are defined as “including costs associated with the Program Administrator and the Low-Income

¹ SB 1547 Section 22. (7)(c-d)

² OAR 860-088-0160(1)(b)

Facilitator. There is no mention of utility ongoing administrative costs. If anything, the rules suggest that any incremental investments made by utilities to support the administration of the program are to be deemed “start-up” costs, and therefore recoverable through rates. Though Staff has confirmed that this question remains unresolved and it was called out as something under consideration in the Utility Data Exchange Subgroup (see July 9 meeting notes), the proposals for PacifiCorp and Idaho Power (PGE did not address the issue) suggest there will be ongoing utility administrative costs recovered from participants.

In addition to relying on the stated rules, it’s worth noting that utility investments could spill over to benefit other utility operations – unlike the Program Administrator functions - which would in turn further justify placing the recovery of those costs on all rate payers rather than just the community solar participants. Finally, the Solar Parties would argue that utility administrative cost recovery could be one area to reduce the cost of participation and improve the program economics more generally, which we’ve highlighted as a concern in previous comments submitted under UM 1930.³

- **Using RVOS as a basis for determining rate impacts.** The resource value of solar (RVOS) should be used as the basis when considering the incremental funds associated with utility compensation for subscribed power, rather than using standard practices associated with avoided cost rates. Measuring the delta between the RVOS and credit rate would provide a more accurate assessment of any incremental rate impact (positive or negative) attributed to the community solar program. It would also be a step toward the PUC’s stated intent to continue considering the role of RVOS in support of the program’s credit rate. That said, the Solar Parties would also note that the RVOS methodology itself is deserving of continued improvements and that we do not view its current state as capturing the most comprehensive value for distributed solar generation.
- **Defining the transition from start-up to ongoing costs.** Delineating the start-up and ongoing costs of administration and associated transition are critical aspects of the overall program design and cost recovery assumptions. For example, if no money is being collected because there is a lack of program participation or simply due to the delay between pre-certification and certification, the PA may not be receiving adequate funding to support their operations. This issue was discussed during a Utility Data Exchange Subgroup meeting last year (see attached Nov. 8, 2017 Meeting Minutes), and the concept of phasing the program cost recovery transition was introduced as a reasonable solution. In essence, there was recognition that there will likely need to be a minimum number of projects developed and customers enrolled to ensure a sustainable recovery of administrative costs. The Solar Parties recommend using the interim capacity allocation (25% of the initial capacity tier) as the “start-up” phase of the program whereby all administrative costs incurred through the pre-certification of that capacity are considered “start-up.”

³ See OSEIA-CCSA comments submitted April 30, 2018.
<https://edocs.puc.state.or.us/efdocs/HAC/um1930hac164146.pdf>

There are two other important and related considerations. First, the Solar Parties recommend that the calculation of any ongoing administrative costs be established based on an expectation that - at least - the entire initial capacity tier of the program is certified and operating, so as not to penalize first-mover participants with higher administrative fees. Instead, these costs should be spread evenly across the entire anticipated program. In addition, any administrative fees on participants - or lack thereof as we suggest for the interim capacity allocation - should never increase on a given project and its participants after pre-certification. Uncertainty in this area could create significant risk for participants and investors. That said, the administrative fee should be able to decline for existing projects and participants if those administrative costs go down as the program expands (e.g., a second capacity tier is established).

The Solar Parties appreciate this opportunity to provide input on the administrative cost recovery for the program and we look forward to further discussions around this topic.

Respectfully submitted,

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[Utility Data Exchange Subgroup-Nov.082017-Minutes]

Meeting Minutes

[Date of meeting]

Organizations Present: PGE, PacifiCorp, Idaho Power, OPUC Staff, ODOJ, ETO, CUB, Renewable Northwest, Climate Jobs Portland, CEC, (there were others as well I just lost count)

Next meeting: TBD Lloyd Center

Program Flow Chart Discussion

Numerous issues were discussed an updated flow chart will be circulated

Subscription Type Limitations

The discussion tried to determine if there were rational limitations that should be placed on the type of subscriptions that can be offered to participants.

Common Understanding: Individual customer subscription amounts will be calculated and tracked by the third party administrator and provided to the utility. This provides some flexibility in the type of subscription structures that could be permitted. A competing concern is the ability to communicate this information on customer bills. For the utility to be able to communicate computation type information (shares*price= monthly cost) the format for subscriptions must be consistent for all on bill collections. This would limit the flexibility for subscription models that are collected on bill. If the expectation is that information presented on the bill is just limited to the total, with detailed information provided through another system, then there is significant flexibility.

There was also uncertainty regarding whether on bill subscription collection is mandatory or permissive? The group thought permissive use of the billing system for subscription collection was better.

Action Items:

- 1) Clarify with Commission whether on bill subscription collection is permissive or mandatory.
- 2) CEC (Charlie Coggeshall) volunteered to survey likely project managers for different varieties of subscription models to educate the group.

On Bill Display

Discussion focused on potential limitations in the type and amount of information that can be provided on the bill. This built on the previous discussion related to subscription type and on bill display limitations.

Primary Question: Subscription Cost and Energy Credit should be shown as separate line items. The question is how to reflect administrative costs. Should they have a separate line item, or should they be included in either of the other two line items as a modification to the total.

Actions Item: The utilities agreed to determine what limitations there are on what information can be provided on the bill. (For example character limits, imbedded computations and the like). They also would try to bring bill mock ups to illustrate the issues if possible.

Customer Information and Privacy Requirements

Discussion focused on customer usage information and how project managers would access that.

Common Understanding: The program administrator will have access to customer usage information through a Consumer Information Transfer Agreement similar to the agreement currently in place between ETO and the utilities. The program administrator will seek approval from the Commission of the necessary consent requirements that a project manager must get from a potential participant before this customer information can be shared with the project manager. The commission should also determine limits of what type of information can be shared.

Action Item: None for now

Tariff Regulatory Structure and Timing

Discussion was designed as a brainstorm session on the potential required dockets and different areas for needed commission approval. It also tried to set a high level timeline of one these dockets should begin. The table below reflects the consensus.

Issue	Who	Initiated?
Standardized QF/PPA Agreement between the utility and Project Managers for Unsubscribed Energy	Each Utility	1 st Quarter
Utility Cost Recovery Balancing Account	Each Utility	1 st Quarter
Utility Deferred Accounting Approval	Each Utility	ASAP
Community Solar RVOS Tariff	Each Utility	2 nd Quarter
Community Solar Program Tariff for Customers	Each Utility	Late 2 nd Quarter
Company Project Tariff	Each Utility	Upon decision to initiate project
Data Privacy Docket	Program Administrator	2 nd Quarter
Program Handbook Approval	Program Administrator	When Complete

Additional Issues Identified: It was unclear if a standard contract would be necessary between the utility and a participant in a third party community solar project, or if the standard program tariff would suffice. If a contract is required an additional docket is required to approve those contracts.

Administrative Cost Recovery Discussion

Discussion was designed as a brainstorming session on how to delineate between start-up costs and on-going costs of administration.

Useful visioning considerations: The preliminary discussion focused on should the delineation be based on a timing issue or a money collected issue. There was general agreement that potential program administrators may have useful thoughts on how to draw this line. A phasing concept was raised as a way to potentially discuss the topic using the same language.

Phase	Description	Recovery Responsibility
Phase 1	Program Development: all expenses related to developing the structure of the program	General Ratepayers

Phase 2	Precertification/Initial Project Development Stage: Projects have been pre-certified but no projects are completed so no participants are contributing administrative costs	General Ratepayers
Phase 3	Initial Program Operations: Early projects are coming on line, Administrative costs are being collected from participants, those collections are insufficient to recover all administrative costs	Shared
Phase 4	Ongoing Program Operations: Sufficient projects are developed and customer enrolled to cover all administrative costs	Participants

The discussion revolves around how the administrative costs in Phase 3 of the program are collected.

An additional concern was on establishing initial administrative costs. The requirement is that project managers provide accurate financial estimates to potential participants. In order to provide this the participant's share of administrative costs must be known. The thought was that the Administrative costs could be set for a project during precertification, and this would then operate as a ceiling for that project. When sufficient additional projects came online these costs could be reduced to reflect the larger pool of participants that are sharing the costs

Roundtable Issues

Issues identified for future discussions

- How customer non-payment will impact bill will be treated if they are a community solar participant. (Leverage On Bill Repayment principles)
- Discuss Generalized Customer Care requirements for the utility and how those obligations are shared between the Utility, the Program Administrator, and the Project Managers.
- Is a low income specific RVOS the proper way to encourage/incentivize low income participation.

Appendix D

OPUC Staff Memo: Community Solar Implementation Update November 20, 2018

ITEM NO. 4

**PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: November 20, 2018**

REGULAR CONSENT EFFECTIVE DATE _____ N/A _____

DATE: November 13, 2018

TO: Public Utility Commission

FROM: Caroline Moore *CM*

THROUGH: Jason Eisdorfer *EP* and JP Batmale *JPB*

SUBJECT: OREGON PUBLIC UTILITY COMMISSION STAFF:
(Docket No. UM 1930) Community Solar Implementation Update.
Information only.

STAFF RECOMMENDATION:

Informational filing - no recommendation.

DISCUSSION:

Issue

This report provides an update on two key Community Solar Program (CSP) implementation milestones:

1. The competitive selection of the CSP Program Administrator (PA); and
2. The establishment of the process by which utilities will recover program start-up costs.

Applicable Law

CSP Program Administrator

Section 22 of Senate Bill (SB) 1547, effective March 8, 2016 and codified in Oregon Revised Statute (ORS) 757.386, directs the Public Utility Commission of Oregon (Commission) to establish a community solar program (hereinafter referred to as "Community Solar Program", "Program", or "CSP").

Division 88 of Chapter 860 of the Administrative Rules specifies that the Commission will select a CSP Program Administrator (PA) and Low Income Facilitator (LIF) through a competitive bidding process.¹

Competitive Procurement

Oregon Administrative Rules (OAR) Chapter 125, Division 246 delegate procurement authority to the Department of Administrative Services (DAS) for procurements exceeding \$150,000. ORS 279B.060 and OAR 125-247-0260 set forth the methods for competitive sealed proposals. A combination of these methods is deployed in the process to procure CSP Program Administrator services.

CSP Cost Recovery

ORS 757.386(7) specifies different treatment for the start-up and ongoing costs of the CSP.

1. Start-up costs: Utilities may recover prudently-incurred program start-up costs as well as costs of energy purchased from CSP projects (Projects) from all ratepayers.
2. Ongoing costs: Owners and subscribers (i.e., program participants) bear the cost to construct and operate Projects, plus ongoing program administration costs.

OAR 860-088-0160(1) clarifies that start-up PA and LIF costs are recoverable in rates of all ratepayers. Further, the rules specify that utilities' prudently-incurred start-up costs recoverable from ratepayers include, but are not limited to, costs associated with customer account information transfer and on-bill crediting and payment, but exclude any costs associated with the electric company developing a project.²

OAR 860-088-0160(2) clarifies that ongoing PA and LIF costs are collected from CSP participants.³

Analysis

Background

At the September 25, 2018 Public Meeting, Staff provided an information only status update on UM 1930 Community Solar Program Implementation. In its update, Staff committed to provide two subsequent updates to the Commission:

- 1) A timing update if a contract for PA services is not executed within 60 days of the September 25, 2018 Public Meeting.

¹ OAR 860-088-0020(1) and OAR 860-088-0030(1).

² OAR 860-088-0160(1)(b).

³ The program rules do not specify recovery for utilities' ongoing costs.

- 2) An update on efforts to agree on the processes by which utilities will recover CSP start-up costs no later than November 2018.

This report is intended to provide the above two updates.

PA Contract Update

A contract for PA services has not been executed, and the solicitation remains in the contract negotiation phase led by DAS. Per state rules, DAS will remain the single point of contact throughout the remainder of the negotiation phase. At the September 25, 2018 Public Meeting, Staff estimated that contract negotiations could take 60 – 90 days. Staff now anticipates that the process will require at least 90 days, with the possibility of exceeding this timeframe. While contract negotiation is proving lengthier than anticipated, it represents the time required for DAS to adhere to state law and its firmly established procurement processes. Staff will continue to work with DAS to focus their efforts on three key principles:

- Ensuring the complete and timely delivery of these complex services;
- Transparency of process; and,
- Securing the best value for ratepayers.

Staff will notify the Commission when contract negotiations are complete, at which point the contract can be presented to the Commission for approval.

Cost Recovery Update

Utilities, stakeholders, and Staff have continued to work together to resolve start-up cost recovery issues by the end of November. A summary of progress is provided below.

On October 22, 2018, parties participated in a workshop to work through unresolved issues related to the utilities' proposals for recovery of both PA/LIF and utility start-up costs. Key takeaways from the workshop include⁴:

- There is general agreement with the utilities' proposals to recover PA/LIF start-up costs.
- The utilities will not be able to provide detailed information about the magnitude of anticipated utility start-up costs until the PA can provide detailed guidance about utility requirements to facilitate the program.
 - Idaho Power Company expects its billing system will be able to handle the requirements without expensive upgrades. Portland General Electric and PacifiCorp were not able to offer that supposition.

⁴ For a description of all CSP cost, see UM 1930 Community Solar Implementation Staff Report for the September 25, 2018 Public Meeting (Item No. 2), p. 4- 6.

- Utility deferral of capital utility start-up costs should follow the guidance provided in Docket No. UM 1909 Investigation of the Scope of the Commission's Authority to Defer Capital Costs. Utilities committed to filing deferrals for recovery of PA/LIF and utility start-up costs when this guidance is available.
- Utilities will file tariffs to recover PA/LIF and utility start-up costs when the PA/LIF's costs and utility requirements are known.
- Stakeholders and utilities shared thoughtful ideas for the transition between start-up and ongoing costs. Staff is considering these ideas in preparation for execution of a contract and finalization of a budget with the PA.

Following the workshop, additional developments occurred.

- On October 29, 2018, the Commission issued Order No. 18-423 in Docket No. UM 1909, which concluded that ORS 757.259(2)(e) provides the Commission no authority to allow deferrals of any costs related to capital investments.
- Portland General Electric filed an application for deferred accounting treatment of start-up costs associated with non-capital start-up costs on November 8, 2018. Staff is reviewing this application.⁵
- The utilities are working with Staff to address the implications of Order No. 18-423 and develop recommendations needed to implement the Commission's decision. The utilities are reviewing the Commission's guidance and developing new proposed processes for the recovery of capital utility start-up costs.

Staff will continue to update the Commission on the status of cost recovery efforts, including a status update no later than January 2019.

Conclusion

PA Selection

The RFP remains in the contract negotiation phase lead by DAS. Staff will continue to provide updates to the Commission on the status of PA selection.

Cost Recovery

The utilities and stakeholders provided thoughtful discussion at the October 22, 2018 cost recovery workshop. Following guidance from in the Commission related to the deferral of capital costs, Portland General Electric filed an application for application for

⁵ See UM 1977 PGE Deferral of Start-up Costs Community Solar Program Implementation.

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deferred accounting treatment of non-capital start-up costs on November 8, 2018. Staff is reviewing this application.⁶

The utilities are working with Staff to understand the Commission guidance related to deferral of capital costs and developing new proposed processes for the recovery of capital utility start-up costs.

Staff will continue to update the Commission on the status of PA selection and cost recovery efforts, including a status update no later than January 2019.

PROPOSED COMMISSION MOTION:

Informational filing - no recommendation.

UM 1930 Update