UM 2247 – Joint Utility Method for Calculating the Incremental Cost of Subscribed Energy in the Community Solar Program

Staff Draft Recommendation and Request for Comments

July 11, 2022

This document describes the Oregon Public Utility Commission Staff's draft recommendation on a joint utility method for calculating the incremental cost of subscribed energy in the Community Solar Program (CSP or Program). Staff requests written comments on this draft recommendation by July 26, 2022. **Please email comments to puc.filingcenter@puc.oregon.gov.**

Schedule

July 11, 2022 – Draft recommendation posted to Docket No. UM 2247 for public comment
July 26, 2022 – Written public comment due
August 15, 2022 – Staff final recommendation posted to UM 2247
August 23, 2022 – Commission decision at public meeting

Background

Oregon Senate Bill (SB) 1547 (2016), directs the Public Utility Commission of Oregon (Commission) to establish a Community Solar Program. The CSP, codified in Oregon Revised Statute (ORS) 757.386, provides electric company customers an opportunity to share in the costs and benefits of solar generation. Pursuant to ORS 757.386(7)(b) Costs incurred by an electric company under the terms of a Community Solar power purchase agreement are recoverable in the rates of the electric company.

Included in these recoverable costs is the incremental cost of subscribed energy, which is the price difference between the energy generated for CSP participants and what the utility would otherwise generate or purchase from another source. Most recently, in Order No. 21-451, The Commission adopted Staff's recommendation to convene Portland General Electric (PGE), PacifiCorp (PAC) and Idaho Power (IPC) for their development of a joint utility methodology for calculating the costs of subscribed energy within the Program. A joint methodology would protect customers of the three utilities by ensuring the same treatment with respect to cost recovery.

PGE, PAC and IPC have submitted separate proposed methods for calculating the incremental cost of subscribed energy. IPC's proposal and workpapers are included as Appendix A. PAC's proposal is also included as Appendix A. However, PAC's workpapers, which were provided as Microsoft excel files, are not included. Staff finds that converting PAC's workpapers to .pdf format would require significant reformatting that could impact the integrity of PAC's workpapers. As a result, Staff are including PAC's proposal and workpapers, as an excel file, as attachments in the service list email associated with posting this draft recommendation. Stakeholders can also obtain PAC's workpapers as an excel file from Staff by emailing the Staff contact listed at the bottom of this document. Finally, PGE has indicated it will separately post its proposal and workpapers to Docket No. UM 2247.

Staff has analyzed PGE, PAC and IPC proposals. As each utility has differences in its accounting software, regulatory divisions, and system operations, Staff finds it reasonable to allow some variance in the recovery mechanisms provided the same resulting customer rate impacts. It is important to note that this program is additive in nature, or in other words, these are not resources that have been procured based on a need to serve customer load. Because of this, non-participating customers would be paying for the variable costs of the energy being generated by these resources through their standard power cost rates if this program did not exist.

Oregon ratepayers pay for the variable costs of the power they consume through annually updated rates on a forecasted basis. Each year, each electric utility runs a power cost model that identifies the most economical way to serve next year's forecasted loads. The model determines this based on forecasted market prices, the costs to operate utility-owned resources, and any contracts that the utility has entered into. Power cost recovery also includes a true-up mechanism, which is backward looking, comparing actual costs to the forecasted cost from the previous year. If the forecast is sufficiently different from the actual cost, then customers are either charged or credited with the difference over the following year.

To properly account for the costs associated with the Community Solar Program, each utility must start with the credit being paid to participants, but also account for the costs that non-participants will pay for the same energy in the utilities annual power cost filing. Each utility utilizes the same formula to calculate the incremental cost of subscribed energy:

Customer Credits for Subscribed Energy – Foregone Replacement Value of Subscribed Energy = Incremental Cost of Subscribed Energy

The first term in the formula, customer credits for subscribed energy, reflects the value of the energy generated by the CSP resources for which Program participants have subscribed. This credit has been set previously by the Commission[1,2]. The "Incremental cost of subscribed energy" is the term of interest, which as previously mentioned is the additional amount paid for by non-participants in order to make the overall program costs balance revenues. The middle term, "Foregone Replacement Cost of Subscribed Energy," accounts for the standard power cost recovery process, subtracting out what non-participants will pay for through regular power cost rates. Thus, if the middle term in the equation, Foregone Replacement Value of Subscribed

[1] Order No. 19-392. https://apps.puc.state.or.us/orders/2019ords/19-392.pdf
[2] Order No. 21-317. https://apps.puc.state.or.us/orders/2021ords/21-317.pdf

Energy, is the same across all three utilities, then the final term will also be the same across all three utilities. When this is the case all ratepayers subject to the Commission's regulation will pay commensurate costs for the program.

Staff includes relevant definitions for terms in this draft recommendation at the end of this document.

Staff Analysis of Utility Proposals

While the three methods proposed have small differences in recovery mechanisms, Staff finds the Foregone Replacement Value of Subscribed Energy and the resulting costs paid by participating and non-participating utility customers are essentially the same. The three methods also avoid double-counting. As a result, Staff finds the three proposals to be sufficiently aligned to recommend as a joint utility methodology.

All three utilities have identified a consistent and similar way to recover the incremental cost of subscribed energy from ratepayers, which is to utilize a Mid-C forward market-based rate as a proxy for the Foregone Replacement Value of Subscribed Energy. The idea being that if the CSP resources did not exist, or the energy was not being utilized by Cost of Service (COS) customers, the utilities could buy or sell the energy from the market. Thus, the value to all customers is the market price for the replacement power. This is a similar approach to the method PAC uses in its Volumetric Incentive Rate Program, and PGE utilizes in its Solar Payment Option. Because the customer credits for participants and the replacement cost estimates are the same, the incremental costs of the subscribed energy are also the same across all three utilities.

The differences between the utilities' proposed methods lie in the mechanisms by which each utility recovers the incremental cost of subscribed energy. PGE's proposed method uses a deferral, which will track the incremental costs, or the difference between the credit and market price of the energy. PGE's proposal is also completely separate from the Company's annual power costs recovery mechanisms. PGE's power cost recovery mechanisms, which include the Annual Update Tariff and the Power Cost Adjustment Mechanism (PCAM) will operate as if the CSP resources do not exist. MONET, PGE's power cost forecasting model, will identify the most economic resource available, whether from the market or self-generated, to fill the void of the CSP resources.[3] In other words, PGE's methodology treats the market price portion of its CSP incremental energy cost calculation as equivalent to the actual avoided variable energy cost in its annual power cost modeling. PGE would then recover the incremental cost of the CSP program from its customers through Schedule 136.

IPC's proposed method forgoes a separate deferral and instead tracks the incremental costs of the subscribed energy through IPC's PCAM. The PCAM is a unique deferral that annually tracks the differences between forecasted and actual power costs. Standard PCAM items have a

[3] This is for instance when the CSP resources generation occurs when the utility is short. In occurrences of generation when the Company is long (generation exceeds load), MONET will simply not be selling the additional energy to the market.

deadband, earnings test, and sharing mechanisms applied, but IPC proposes to not subject the CSP costs to these mechanisms and instead have the PCAM function as a one-for-one true-up for the incremental costs. Although this is somewhat unusual, it is not outside the standard treatment for certain costs within power cost recovery generally. The important aspect in the forecast/true-up process is ensuring an apples-to-apples comparison. If a cost is not included in the forecast then it shouldn't be included in the standard true-up process for calculation in the deadband. Recovery of a cost outside of the standard mechanisms (deadband, earnings test, sharing) effectively removes it from the forecast/actual PCAM process and maintains an apples-to-apples comparison for all other costs.

PAC's proposed method utilizes a blend of the approaches proposed by PGE and IPC to recover the incremental cost of subscribed energy. Like PGE, PAC proposes to track the incremental costs in a separate deferral. Unlike PGE, PAC proposes to include the CSP resources in its power cost forecast, the Transition Adjustment Mechanism (TAM), and true-up within its PCAM. The resources however, will be priced at the blended Mid-C market price PAC is utilizing in its calculation of the incremental costs for the CSP program, and set as a "must-run" resource so that the their power cost model will always utilize that energy.

Staff finds PGE's proposed method to be the simplest of the three, and likely most beneficial to ratepayers because it completely avoids concerns over treatment in the power cost filings. PGE's method, however, may be subject to small mismatches in recovery for shareholders when the power cost model is able to identify cheaper resources than market for the replacement power. PAC's and IPC's method will avoid mismatches between the market value of the subscribed energy in power costs but at the cost of additional complexity.

Staff Draft Recommendation

Staff finds the three proposed methods appropriately calculate the incremental cost of subscribed energy. Staff also finds differences in how each method recovers costs yields minimal differences in costs borne by ratepayers. As a result, Staff recommends approving the three proposals as a joint utility method.

Definitions

Mid-C forward market-based rate: A price for energy in some future period at the Mid-Columbia energy hub located near Wenatchee, Washington. The forward market curve shows the price of power being offered to be bought or sold during a given timeframe.

Cost of Service Customers: Any customer who pays a utility's standard rates for energy. This includes an amount for the fixed costs, variable costs, and a Commission-determined reasonable return on investment for the Company's shareholders.

Volumetric Incentive Rate Program: A pilot program offered by PacifiCorp for customers who own a form of solar generation which allows the customer to sell electricity generated back to the utility.

Solar Payment Option: A pilot program offered by PGE for customers who own a form of solar generation which allows the customer to sell electricity generated back to the utility.

Power Cost Adjustment Mechanism: A general term for the true-up or backward looking portion of a utility's power cost recovery process which compares forecasted power costs to actual power costs over the course of the previous year.

Annual Update Tariff: The name for PGE's power cost forecast filing. Filed annually in April, the AUT sets the price of variable power that customers pay for the upcoming year. This is in addition to the fixed cost portion of rates set in general rate cases.

Power Cost Forecasting Model: A model which identifies the least-cost way to serve expected loads. The models generally take market price forecasts, utility-owned generation characteristics, and any contracts for energy the utility has entered into in order to identify the cheapest way to meet customer load in every hour for the upcoming year.

Transition Adjustment Mechanism: The name for PacifiCorp's power cost forecast filing.

Deadband: Utilized in Power Cost Adjustment Mechanisms as a way to determine what cost variances are usual and what cost variances are abnormal. The Commission determines a set amount (generally $15 million over-recovery and $30 million under-recovery) by which forecast vs actual power cost deviations are examined. If the deviation is outside the deadband (i.e., either greater than $15 million in over-recovery or $30 million in under-recovery of costs) then the amount outside the deadband is recoverable in rates.

Earnings Test: A test utilized to determine if the recovery of a specific class of costs is warranted based on the utility's overall recovery of costs. Earnings tests examine how close the utility was to earning its authorized rate of return over the course of the previous year, if the utility recovered all costs within a set range, then the specific costs being considered for amortization are deemed as non-recoverable. This is important in power costs, where additional load can result in under-recovery of variable costs, but over-recovery of fixed costs because customer rates are largely charged on a per kWh basis. Earnings tests attempt to ensure that customers are not paying additional amounts for particular costs when they already paid excess amounts for costs overall.

Sharing Mechanisms: A means to share costs or risks amongst ratepayers and shareholders. Shareholders must bear some risk as a result of the return on investment they hope to earn. The Commission may deem some costs or risks as being more equitably shared between ratepayers and shareholders, usually at a 90/10 split, where ratepayers bear 90 percent of the costs and shareholders bear 10 percent.

How to submit comments

Please submit any comments on this draft recommendation for the UM 2247 docket by email to puc.filingcenter@puc.oregon.gov by July 26, 2022.

Staff contact

Joe Abraham, Utility Analyst, joseph.abraham@puc.oregon.gov, 503-428-0699

Appendix A. IPC and PAC Proposed Methods for Calculating the Incremental Cost of Subscribed Energy in the Community Solar Program.

Idaho Power Company Proposal

Exhibit 303, included below, is filed annually with the March Forecast of the APCU. The monthly HL forward price curves are applied to the subscribed energy for the month to determine the avoided energy value total. That amount is then subtracted from the bill credits paid for the month to determine the incremental amount that would be recovered from all OR customers. The avoided energy total would be included in the PCAM calculations of actual power supply costs and not subject to deadbands. The following table is a full year example of the Company's proposal based on the forward market prices in the first attachment.

IDAHO POWER COMPANY Exhibit 303
Mid-Columbia Heavy Load and Light Load Daily Forward Curves
Used to Re-Price Purchased Power (PP) and Surplus Sales (SS) for the APCU March Forecast

Line	Mid-Columbia Forward Price Curve on:												
1	**3/18/2022**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**
2	**mc HL**	39.05	29.05	37.55	84.70	150.25	95.50	60.65	61.20	81.10	82.35	71.20	45.70
3	**mc LL**	36.55	21.55	20.25	38.40	58.45	62.45	52.40	51.15	64.70	66.70	58.40	36.20
4	**Reallocated Prices**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Nov-22**	**Dec-22**	**Jan-23**	**Feb-23**	**Mar-23**
5	**HL PP**												
6	100.0%	39.05	29.05	37.55	84.70	150.25	95.50	60.65	61.20	81.10	82.35	71.20	45.70
7	**LL PP**												
8	100.0%	36.55	21.55	20.25	38.40	58.45	62.45	52.40	51.15	64.70	66.70	58.40	36.20
9	**HL SS**												
10	100.0%	39.05	29.05	37.55	84.70	150.25	95.50	60.65	61.20	81.10	82.35	71.20	45.70
11	**LL SS**												
12	100.0%	36.55	21.55	20.25	38.40	58.45	62.45	52.40	51.15	64.70	66.70	58.40	36.20

	Heavy Load	Light Load
Jan-23	82.35	66.70
Feb-23	71.20	58.40
Mar-23	45.70	36.20
Apr-22	39.05	36.55
May-22	29.05	21.55
Jun-22	37.55	20.25
Jul-22	84.70	38.40
Aug-22	150.25	58.45
Sep-22	95.50	62.45
Oct-22	60.65	52.40
Nov-22	61.20	51.15
Dec-22	81.10	64.70

Idaho Power Company
Community Solar Cost Recovery Proposal
July 2022

Estimated kWh generation shaped by PV Watts Solar monthly Output
Estimate 2.95 MW in Ontario
Subscribed Generation 100%

Month	AC System Output (kWh)	Subscribed Generation (kWh)	HL Rate	Avoided Energy Value*	Energy at Subscribed Bill Credit Rate .088/kWh	Rate Impact**
1	198,387	198,387	$82.35	$16,337.17	$17,458.06	$1,120.89
2	335,045	335,045	$71.20	$23,855.20	$29,483.96	$5,628.76
3	562,703	562,703	$45.70	$25,715.53	$49,517.86	$23,802.34
4	785,252	785,252	$39.05	$30,664.09	$69,102.18	$38,438.09
5	914,548	914,548	$29.05	$26,567.62	$80,480.22	$53,912.60
6	928,547	928,547	$37.55	$34,866.94	$81,712.14	$46,845.20
7	967,718	967,718	$84.70	$81,965.71	$85,159.18	$3,193.47
8	870,247	870,247	$150.25	$130,754.61	$76,581.74	($54,172.88)
9	685,027	685,027	$95.50	$65,420.08	$60,282.38	($5,137.70)
10	498,605	498,605	$60.65	$30,240.39	$43,877.24	$13,636.85
11	279,105	279,105	$61.20	$17,081.23	$24,561.24	$7,480.01
12	174,816	174,816	$81.10	$14,177.58	$15,383.81	$1,206.23
Total	7200000***	7,200,000		$497,646	$633,600	$135,954

* This amount would be recorded to the PCAM for actual power supply costs and not subject to deadbands
** This incremental amount would be collected from all customers through a TBD mechanism
***Annual energy estimate in PPA

PAC Proposal

PAC’s proposal is included below. PAC's associated workpapers, which were provided to Staff as Microsoft Excel files, are not included due to significant reformatting that would be required. Staff have also include PAC’s proposal and workpapers, as an excel file, as attachments in the service list email associated with posting this draft recommendation. Stakeholders can also obtain PAC’s workpapers as an excel file from Staff by emailing the Staff contact listed immediately before Appendix A.

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

Updated: May 12, 2022

RE: PacifiCorp Proposal for Oregon Community Solar Calculation of the Incremental Cost of Subscribed Energy

History: In Order 21-148, the Public Utility Commission of Oregon approved PacifiCorp's proposal to include the incremental costs associated with subscribed energy in the Community Solar Deferral originally approved in Order 18-478. In the Order, it was noted that the method for calculating the incremental costs of subscribed energy had not yet been determined, and that staff planned to work with stakeholders and all three utilities to develop a common method for calculation.

On April 18, 2022, Staff held a workshop where the utilities presented their proposed approach for calculating this incremental cost of subscribed energy. PacifiCorp presented a draft proposal at the workshop and since that time has refined its proposal which is presented below.

Proposed Calculation of the Incremental Cost of Subscribed Energy
The incremental cost of energy is determined by calculating the market value of the energy that is subscribed and then subtracting that value from the credits provided to participating customers. The incremental cost is then booked to the deferral and collected from all customers through Schedule 207: Community Solar Start-up Cost Recovery Adjustment. The calculated energy value is included within energy costs as purchased power.

Customer credits for subscribed energy – Market Cost of Subscribed Energy = Incremental Cost of subscribed energy

PacifiCorp proposes to include the community solar project(s) in its forecast production cost model for the TAM. The resources will be modeled using the must run setting and priced at the forecast blended Mid-C market price. The blended Mid-C market price is the MID-C market price weighted at 85% HLH and 15% LLH. This is the same methodology used for the Volumetric Incentive Rate Program.

The actual net power costs in the PCAM will capture the blended Mid-C market price used in the TAM for the community solar project resources. The difference between the incentive rate and the forecast market price will be booked to the deferral.

After discussions with PGE around their approach, in order to achieve the same outcome as PGE, it is necessary to reflect a forecast of the market value of this resource in PacifiCorp's TAM (NPC forecast). If this resource is not modeled in the TAM, then PacifiCorp's production cost model will instead choose a different resource (the least cost resource in the generation stack, regardless of whether it is coal, gas, hydro, market purchase) to meet the obligation that is being met in reality by the CSP Resources. This will lead to a disconnect between the TAM which will not contain this resource and the PCAM, which will contain this resource. As a result of the deadbands and sharing bands in the PCAM, customers will neither get benefit when the CSP resources are priced below the marginal unit cost in the resource stack, nor will they bear the cost when the CSP resources are above the marginal unit cost in the resource stack. By modeling the CSP resources as must run and priced with the same methodology that is used to develop the price for the PCAM, the only variance between the TAM and the PCAM will be the difference between forecasted and actual generation.

Portland General Electric Proposal

PGE has indicated it will separately post its proposal and workpapers to Docket No. UM 2247.