BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 73

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2019 Integrated Resource Plan	THE RENEWABLE ENERGY COALITION'S COMMENTS ON THE IRP UPDATE

I. INTRODUCTION

The Renewable Energy Coalition (the "Coalition") provides these comments on Portland General Electric Company's ("PGE's") 2019 Integrated Resource Plan ("IRP") Update. The sole reason PGE seeks acknowledgment is to update its avoided cost pricing, and the most significant change to that pricing will be to reduce the value of solar resources.[1] PGE has not adequately supported the changes to its IRP nor its pricing. Therefore, the Oregon Public Utility Commission (the "Commission") should *not* acknowledge PGE's 2019 IRP Update.

Based on discovery, the Coalition understands that a significant driver for the reduced solar pricing is PGE's inclusion of approximately 200 MW of additional solar resources in the Baseline Portfolio.[2] This additional solar generation has the effect of lowering the Effective

---

1 PGE IRP Update at 2 ("PGE respectfully requests that the Commission acknowledge this IRP Update so that we can include the updated inputs in the May 1 avoided cost update filing."); PGE Supplemental Filing at 6 (estimating renewable avoided cost pricing for solar resources will decrease 9% and non-renewable avoided cost pricing for solar resources will decrease 17%).

2 PGE IRP Update at 48; *see also* Att. A (PGE Response to REC Data Request No. 022), Att. B (PGE Response to REC Data Request No. 023), and Att. C (PGE Response to REC Data Request No. 026).

Load Carrying Capability and capacity assumed for solar generation, which lowers avoided costs.[3]

The Coalition has identified two significant concerns with PGE's assumptions at this time. First, PGE continues to overstate the amount of solar qualifying facilities ("QFs") that will come online. PGE continues to assume that all or nearly all will reach commercial operation. A more accurate assumption would reduce or eliminate PGE's forecasted increase in new solar generation and the avoided cost price reduction. The Coalition strongly opposes any further reduction in avoided cost prices driven entirely, or almost entirely, on PGE's steadfast refusal to perform a reasonable estimate of its future expected QFs. If this were any other type of IRP assumption, then PGE would likely make an effort to develop an accurate forecast.

Second, PGE attributes 93 MW to the Oregon Community Solar Program (the "CSP"), half of which PGE assumes will come online in January 2022 and the remainder in January 2023.[4] These assumptions are contrary to prior Commission guidance and factually unsupported.

In addition, the Commission has a pending investigation into the treatment of QFs under the Public Utility Regulatory Policies Act.[5] The Commission has also recognized the need to evaluate changes to avoided cost pricing in light of Executive Order No. 20-04, which PGE has deferred until its next IRP.[6] It would be inappropriate to substantially reduce prices for QFs before the Commission resolves these issues.

---

3 PGE Supplemental Filing at 3; Att. A (PGE Response to REC Data Request No. 022).

4 PGE IRP Update at 29.

5 *See generally In re Comm'n Investigation into Treatment of QFs in Util. IRP Process*, Docket No. UM 2038.

6 Draft 11-12 of Commission Executive Order 20-04 Work Plans at 7, https://www.oregon.gov/puc/utilities/Documents/EO20-04-Draft-Work-Plans.pdf; PGE IRP Update at 24.

Finally, given the short time period to review PGE's filing, the Coalition may raise additional issues in its next round of comments and in PGE's post-IRP acknowledgment avoided cost price filing expected on May 1.[7]

II. COMMENTS

A. The Commission Should Require PGE to Appropriately Plan for QFs

The Coalition supports robust, evidence-based planning, but PGE has not met this standard. The Coalition has longstanding concerns that PGE is not adequately supporting its assumptions about QFs. The Coalition recognizes that the Commission intends to provide guidance to correct these assumptions in a generic proceeding for that purpose, Docket No. UM 2038. The Coalition looks forward to a resolution in that proceeding. The Coalition repeats here its recommendation that "even if that docket has not concluded by the time PGE files its next IRP update or future IRP, the Commission should direct PGE to include an appropriate forecast now and in all future IRPs."[8]

In its IRP Update, PGE assumes in its baseline portfolio that all QFs with executed contracts achieve operations and that there are no additional contracts or contract terminations.[9] PGE has provided sensitivities, one where only half of the QFs with executed contracts achieve operations, and one where all QFs with contracts plus all QFs actively progressing toward contract execution achieve operations.[10] These sensitivities demonstrate that the uncertainty here

---

7 The Coalition identified additional potential issues to raise in these comments. However, the Coalition decided not to pursue some of them after reviewing PGE's discovery responses. The Coalition thanks PGE's IRP team for working to provide responses that resolved certain concerns.

8 Coalition's Comment on the Staff Memorandum at 2.

9 PGE IRP Update at 40.

10 PGE IRP Update at 40.

has potentially significant effects. For instance, PGE estimates that its 2025 Energy Position may vary by almost 150 MWa based on the different QF assumptions.[11]

These assumptions are arbitrary and not based on facts. None of the projected QFs are more than 10 MWs in size.[12] These are small projects that are more difficult to finance, are often developed by less sophisticated companies, and face unique and difficult problems related to their power purchase agreement implementation and interconnections. This means that they tend to have higher failure rates or rates of delay. In addition, approximately 50 QFs in PGE's analysis have *already* missed their scheduled commercial operation date ("COD"), yet PGE assumes *all* of them will still come online by July 1, 2020.[13]

PGE should conduct a historical survey of how many QFs actually came online, came online by their COD, or ultimately failed. PGE is in possession of this kind of data and the Coalition does not see any reason why these kind of relevant metrics should be disregarded. Such a survey would yield a much better assumption for future QF development than PGE's unrealistic 100% success assumption. The Commission should not acknowledge an IRP Update for the sole purpose of lowering avoided costs when PGE is relying on unsupported assumptions.

B. The Commission Should Require PGE to Appropriately Plan for the CSP

PGE's assumptions underlying the CSP are contrary to the PUC's prior guidance and factually unsupported. The Commission should reject PGE's assumptions. Further, the Commission should provide additional clarity for all utilities on how to treat the CSP in IRPs.

---

11 PGE IRP Update at 41 (indicating a potential range from 491 MWa to 635 MWa).
12 Att. D (PGE Response to REC Data Request No. 028).
13 PGE Response to REC Data Request No. 028, Att. A.

In the 2019 IRP, PGE's base case assumed zero participation in voluntary green energy programs.[14] The Commission expressed concern with this assumption but did not specify what PGE ought to assume instead.[15] PGE relies upon this concern to justify its substantially changed assumptions for the CSP. Specifically, where PGE previously assumed zero participation, PGE now assumes that 93 MW of CSP resources will be operational by January 2023, with half beginning a year earlier in January 2022.[16]

Notably, PGE's assumptions appear to be inconsistent with the Commission's earlier guidance on how to treat CSP resources in the IRP. In the rulemaking for the CSP, the Commission adopted the following two components for the IRP:

1. When calculating generation assets in its integrated resource planning, an electric company must include in its supply mix all energized community solar projects participating in the Community Solar Program.
2. When assessing load-resource balances in its integrated resource planning, an electric company must include forecasts of market potential for community solar projects and analyses comparing historical forecasts and actual community solar project development.[17]

Based on this guidance, it would seem appropriate for PGE to include energized CSP resources in its baseline portfolio and forecast future CSP developments, likely as an IRP sensitivity. PGE did neither.

The only CSP projects in PGE's service territory currently energized and certified together total fewer than 7 MW.[18] Notably, the Commission certified these projects in February

---

14 *See* Order No. 20-152 at 8 (May 6, 2020).

15 Order No. 20-152 at 8 ("[W]e find there is some risk of PGE over-procuring resources if it fails to consider these programs.").

16 PGE IRP Update at 29.

17 *In re Rules Regarding Community Solar Projects*, Docket No. AR 603, Order No. 17-232 at 13 (June 29, 2017).

18 *See In re Comm'n Implementation of CSP*, Docket No. UM 1930, Order No. 21-042, App. A at 2 (Feb. 12, 2021).

2021, while PGE's 2019 IRP Update uses a snapshot date of June 2020.[19] In June 2020, there were *no* energized CSP projects in PGE's service territory. Under the Commission's rulemaking guidance, combined with PGE's June 2020 snapshot date, PGE arguably should include *zero* CSP projects in its baseline portfolio.

Instead of including zero CSP projects or all unbuilt CSP resources in its baseline portfolio, PGE should provide a reasonable CSP resource development forecast. PGE ran a sensitivity analysis for the GEAR program rather than including it entirely in the baseline portfolio, and it remains unclear why PGE did not take the same approach for the CSP.[20] As a forecast, PGE could consider the proposed projects in its CSP queue, which currently total approximately 35 MW, including the energized projects.[21] It may be appropriate for PGE to assume that a portion of these 35 MW come online by January 2022, but there could be unexpected delays during development.

Instead of assuming 7 MW (the amount energized) or even 35 MW (the pending capacity), PGE's 2019 IRP Update assumes *93 MW* of CSP resources will come online by January 2023.[22] At this time, the Commission has only approved 47 MW of CSP capacity, and it is unclear today—just as it was on PGE's snapshot date roughly nine months ago—when the

---

[19] PGE IRP Update at 30.

[20] PGE IRP Update at 39; Att. E (PGE Response to REC Data Request No. 025) ("The 2019 IRP Update did not include a sensitivity of the Community Solar Program because the program is included in the Baseline Portfolio"). Notably, PGE ran a sensitivity for the GEAR capacity that had not been "finalized" by the snapshot date, and PGE agreed that not all of the CSP capacity had been "finalized" by the snapshot date either. Att. E (PGE Response to REC Data Request No. 025).

[21] Att. E (PGE Response to REC Data Request No. 025) ("The Community Solar program was launched in January 2020 with the first 46.57 MW in the interim offering. Of the 46.57-MW interim offering, the general capacity is filled, and 11.6 MW of carve-out capacity remains.")

[22] PGE IRP Update at 29.

Commission might approve opening the other 47 MW of capacity.[23] When asked for support for the inclusion of this 47 MW, and for assuming it would be operational by 2023, PGE responded that it "does not project a specific launch date" and did this for "modeling purposes."[24] Again, PGE included these 47 MW of non-approved, unbuilt resources in its *baseline* portfolio. The Commission should refuse to acknowledge PGE's 2019 IRP Update when its baseline portfolio includes 47 MW of capacity that is not, and by rule *cannot be,*[25] constructed at this time or in the known future.

PGE's changed CSP assumptions are effectively a change from 0% to 200%. While the Coalition agrees with the Commission's prior recommendation that PGE appropriately plan for the CSP, PGE has over-corrected. The Coalition reminds the Commission that the sole purpose of this overcorrection is to update avoided cost pricing, which will ultimately discourage the development of independent renewable energy in Oregon.

The Coalition wants to be clear that it appreciates PGE's support for the CSP and its optimism for the future of the program, and the Coalition's concerns regarding the CSP in the context of the IRP are tied solely to ensuring that there is an accurate forecast for how many and when the CSP projects will come online. PGE is and continues to be a valuable partner in assisting the development of a functioning and equitable CSP in Oregon. The Coalition believes

---

23 Docket No. UM 1930, Order No. 19-392 at 4 (Nov. 8, 2019) (setting the interim tier for PGE at 50 percent of the initial program capacity tier); Docket No. UM 1930, Order No. 19-392, App. A at 66 (noting PGE's initial program capacity tier is 93.15 MW).

24 Att. F (PGE Response to REC Data Request No. 019).

25 The CSP Program Implementation Manual specifies that projects cannot begin development until after they are pre-certified, meaning the Commission has opened space and the project received a spot in the queue. Oregon CSP Program Implementation Manual at 14 (eff. Jan. 13, 2021), https://www.oregoncsp.org/p/ProgramImplementationManual.

that the CSP furthers decarbonization of energy supply in Oregon and provides a public benefit and a public good that benefits all customers.

III. CONCLUSION

For the foregoing reasons, the Commission should decline to acknowledge PGE's 2019 IRP Update and instead order PGE to plan appropriately for both QFs and the CSP. The Coalition is continuing to review PGE's IRP Update and reserves the right to raise the same or additional concerns.

Dated this 10th day of March 2021.

Respectfully submitted,

Sanger Law, PC

Irion A. Sanger
Joni Sliger
1041 SE 58th Place
Portland, OR 97215
503-756-7533 (tel)
503-334-2235 (fax)
irion@sanger-law.com

Of Attorneys for the Renewable Energy Coalition

Attachment A

PGE Response to REC Data Request No. 022

March 2, 2021

TO: Irion Sanger
Renewable Energy Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to REC Data Request No. 022
Dated February 22, 2021

Request:

Please reference PGE's Supplemental Filing at page 4, which states that "1.3.Updated Interconnection Cost … These updates have a minimal impact on avoided cost rates." Please separately provide the estimated impact on avoided cost rates of the updates described in each of Sections 1.1 (Updated ELCC Values), 1.2 (Updated Simple-cycle Combustion Turbine Net Energy Value), Section 1.3 (Updated Interconnection Cost), 1.4 (Updated Combined-cycle Combustion Turbine Annual Generation and Starts), and 1.5 (Initial Estimated Avoided Cost Impact Based Only on IRP Update). Please provide the estimated impact of updates in each section as: 1) a percentage change relative to current avoided cost rates; and 2) a portion of each Initial Estimated Change in Table 4 of PGE's Supplemental Filing for both standard and renewable pricing for each of base load, wind, and solar resources. In other words, separately identify the impact for Sections 1.1, 1.2, 1.3, 1.4 and 1.5.

Response:

PGE objects to this request to the extent that is unduly burdensome, seeks new analysis, and is outside the scope of this proceeding. Subject to and without waiving these objections, PGE responds as follows:

Please see LC 73_REC DR 022_Attach_A. This attachment provides a sequential step log showing the estimated impact on levelized avoided cost rates of updating the ELCC values, SCCT net energy value, Interconnection Costs, and CCCT starts/generation. It also provides the $/MWh change of each step and the percentage of that change relative to current avoided cost prices. Please note that while this shows a rough approximation of the magnitude of each change, the order of the steps can impact the results. For example, because the SCCT net energy value impacts capacity payments, its impact on prices may differ very slightly if it were the first step rather than the second step.

2019 IRP Update - Supplemental
Estimated Schedule 201 Price Change Calculation
Initial estimate of impact of 2019 IRP Update inputs
Step Log Impacts
2024 COD, 15-yr Levelized Prices, 2020$/MWh

	$/MWh	Non-Renewable			Renewable	
Step	Step Description	Base Load	Wind	Solar	Base Load	Wind
0	Current Avoided Cost	32.19	27.99	26.18	48.15	43.95
1	ELCC Values	32.74	27.32	21.54	49.12	43.93
2	SCCT Net Energy Value	32.74	27.32	21.53	49.13	43.93
3	Interconnection Costs	32.74	27.31	22.41	49.34	43.91
4	CCCT Starts/Gen	32.78	27.36	21.69	49.34	43.91

Step 4 is the final step (i.e., it includes all of the IRP Update inputs). The Step 4 levelized pr
the estimated levelized prices based on the inputs from the 2019 IRP Update.

	Step Change, $/MWh	Non-Renewable			Renewable	
		Base Load	Wind	Solar	Base Load	Wind
0	Current Avoided Cost					
1	ELCC Values	0.557	-0.665	-4.643	0.972	-0.021
2	SCCT Net Energy Value	0.001	-0.004	-0.009	0.005	0.000
3	Interconnection Costs	-0.003	-0.002	0.874	0.208	-0.020
4	CCCT Starts/Gen	0.043	0.043	-0.714	0.000	0.000

	% change from Current	Non-Renewable			Renewable	
		Base Load	Wind	Solar	Base Load	Wind
0	Current Avoided Cost					
1	ELCC Values	1.73%	-2.38%	-17.73%	2.02%	-0.05%
2	SCCT Net Energy Value	0.00%	-0.02%	-0.03%	0.01%	0.00%
3	Interconnection Costs	-0.01%	-0.01%	3.34%	0.43%	-0.05%
4	CCCT Starts/Gen	0.13%	0.15%	-2.73%	0.00%	0.00%

Solar
45.05
41.46
41.46
41.20
41.20

rices are

Solar
-3.592
-0.005
-0.257
0.000

Solar
-7.97%
-0.01%
-0.57%
0.00%

Attachment B

PGE Response to REC Data Request No. 023

March 3, 2021

TO: Irion Sanger
Renewable Energy Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to REC Data Request No. 023
Dated February 22, 2021

Request:

Please reference PGE's Supplemental Filing at Table 4.

a. Please provide the Initial Estimated Change in standard and renewable pricing for each of base load, wind, and solar resources if PGE utilized the RECAP model in lieu of the Sequoia model.

b. Please provide the estimated impact on avoided cost rates of the updates described in each of Sections 1.1 (Updated ELCC Values), 1.2 (Updated Simple-cycle Combustion Turbine Net Energy Value), Section 1.3 (Updated Interconnection Cost), 1.4 (Updated Combined-cycle Combustion Turbine Annual Generation and Starts), and 1.5 (Initial Estimated Avoided Cost Impact Based Only on IRP Update) if PGE utilized the RECAP model in lieu of the Sequoia model. Please provide the estimated impact of updates in each section as: 1) a percentage change relative to current avoided cost rates; and 2) a portion of each Initial Estimated Change in Table 4 of PGE's Supplemental Filing for both standard and renewable pricing for each of base load, wind, and solar resources. In other words, separately identify the impact for Sections 1.1, 1.2, 1.3, 1.4 and 1.5.

Response:

PGE objects to this request to the extent that it is unduly burdensome, seeks new analysis, and is outside the scope of this proceeding. Subject to and without waiving these objections, PGE responds as follows:

a. PGE has not conducted the analysis requested. However, the 2019 IRP included a marginal ELCC curve for incremental additions of solar resources and from that curve, an approximation of the impact from adding additional solar to the portfolio used in the 2019 IRP RECAP model can be calculated. LC 73_REC DR 023_Attach_A provides a comparison of the current avoided cost prices, the initial estimate of the avoided cost prices based on the 2019 IRP Update inputs, and estimated prices based on a scenario updating only the solar ELCC value with the 2019 IRP value for the third increment of solar resources (i.e. 7.2%, approximating the impact of the additional solar resources in the Baseline Portfolio). PGE notes that this scenario only impacted the avoided cost pricing for solar resources.

As shown in LC 73_REC DR_Attach_A, the inputs from the 2019 IRP Update result in very similar solar price estimates compared to the prices that could be expected based on the 2019 IRP marginal ELCC curve for incremental additions of solar resources.

b. The adoption of the Sequoia model in place of RECAP for capacity assessment modeling did not affect the changes described in PGE's Supplemental Filing in Section 1.2 (Updated Simple-cycle Combustion Turbine Net Energy Value), Section 1.3 (Updated Interconnection Cost), and Section 1.4 (Updated Combined-cycle Combustion Turbine Annual Generation and Starts), The capacity assessment model only impacts the updated ELCC values provided in Section 1.1.

Please also refer to PGE's response to REC Data Request No. 022, which provides the impacts on the levelized avoided cost prices based on a sequential step log of updating ELCC values, net energy value, interconnection costs, and CCCT starts/generation. This analysis shows that the SCCT net energy value and interconnection cost impacts are minor and that (as stated in the Supplemental Filing), the CCCT update does not impact the renewable avoided cost prices.

2019 IRP Update - Supplemental
Estimated Schedule 201 Price Change Calculation
Initial estimate of impact of 2019 IRP Update inputs
Plus test of 2019 IRP Solar Bin (7.2%) with no other updates
15-yr Levelized Price, 2020$/MWh
% Change values are relative to Current Avoided Cost Prices

$/MWh	Non-Renewable			Renewable	
Step Description	Base Load	Wind	Solar	Base Load	Wind
Current Avoided Cost	32.19	27.99	26.18	48.15	43.95
IRP Update	32.78	27.36	21.69	49.34	43.91
2019 IRP Solar Bin Only	32.19	27.99	22.31	48.15	43.95

Change from Current, $/MWh	Non-Renewable			Renewable	
	Base Load	Wind	Solar	Base Load	Wind
Current Avoided Cost					
IRP Update	0.597	-0.628	-4.491	1.185	-0.041
2019 IRP Solar Bin Only	0.000	0.000	-3.875	0.000	0.000

% change from Current	Non-Renewable			Renewable	
	Base Load	Wind	Solar	Base Load	Wind
Current Avoided Cost					
IRP Update	2%	-2%	-17%	2%	0%
2019 IRP Solar Bin Only	0%	0%	-15%	0%	0%

Solar
45.05
41.20
41.18

Solar
-3.854
-3.875

Solar
-9%
-9%

Attachment C

PGE Response to REC Data Request No. 026

March 3, 2021

TO: Irion Sanger
Renewable Energy Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to REC Data Request No. 026
Dated February 22, 2021

Request:

Please reference PGE's Supplemental Filing at page 3, which states that "the decline in the marginal ELCC value for solar is primarily due to approximately 200 MW of additional solar resource in the Baseline Portfolio since the analysis for the 2019 IRP."

a. Please identify any and all factors besides the approximately 200 MW of additional solar resource in the Baseline Portfolio which contribute to the decline in the marginal ELCC value for solar. For each factor, please provide the approximate effect on the marginal ELCC value using: 1) the RECAP model; and 2) the Sequoia model. For each factor, please provide the approximate impact on standard and renewable avoided cost pricing for solar resources.
b. Please identify all factors which contribute to the decline in the marginal ELCC value for Gorge Wind. For each factor, please provide the approximate effect on the marginal ELCC value using: 1) the RECAP model; and 2) the Sequoia model. For each factor, please provide the approximate impact on standard and renewable avoided cost pricing for wind resources.
c. Please identify all factors which contribute to the decline in the marginal ELCC value for SCCT. For each factor, please provide the approximate effect on the marginal ELCC value using: 1) the RECAP model; and 2) the Sequoia model. For each factor, please provide the approximate impact on standard and renewable avoided cost pricing for base load resources.

Response:

PGE objects to this request to the extent that it is overly broad, unduly burdensome, seeks new analysis, and is outside of the scope of this proceeding. Subject to and without waiving these objections, PGE responds as follows:

PGE has not performed the analysis requested. Please see PGE's response to REC Data Request No. 023, which provides a scenario of Schedule 201 pricing based on the ELCC study from the

2019 IRP. PGE also provides the following information in response to parts a, b, and c of this request:

As discussed in PGE's response to OPUC Data Request No. 189, the 2016 IRP, 2016 IRP Update, and 2019 IRP included ELCC studies that showed declining marginal ELCC values for solar. The solar ELCC values from the 2019 IRP Update analysis are very similar to those from the 2019 IRP when the increase in solar resources is accounted for.

Table 1 shows the values from the 2019 IRP ELCC study for solar compared to the IRP Update with the values aligned to reflect the approximate quantity of solar in the baseline portfolio relative to the 2019 IRP (approximately 200 MW less than in the IRP Update Baseline Portfolio). The 2019 IRP study showed a decline to the marginal ELCC value as more solar resources were added to the portfolio. As expected from that study, the first increment of solar resources for the IRP Update had a lower ELCC value than the first increment of resources in the study for the 2019 IRP (5.5% compared to 15.8%). A more appropriate comparison, however, is between the first increment of the IRP Update and the third increment of the 2019 IRP because these have approximately the same quantity of solar resources in the portfolios (5.5% compared to 7.2%). For the 100 MW increments examined, this is a difference of less than 2 MW.[1]

Table 1. Solar ELCC study comparison based on approximate solar in the portfolio relative to the 2019 IRP

Incremental 100 MW Additions	2019 IRP Solar	IRP Update Solar
100	15.8%	-
200	10.2%	-
300	7.2%	5.5%
400	4.8%	5.0%
500	3.6%	4.5%
600	2.6%	4.0%
700	2.1%	4.0%
800	2.0%	2.7%

There are multiple factors that contributed to the remaining change to the solar ELCC values between the two studies, including: the updated econometric load forecast, the resource updates (e.g., the Douglas PPA, the QF snapshot, market capacity, and the characteristics of the solar resources[2]), and the Sequoia model (e.g., the improved modeling of contingency reserve

[1] As discussed in Section 5.3 of the IRP Update, an ELCC value is a ratio of the capacity contribution of a resource to its project size.
[2] The solar resources added to the portfolio are not identical to the proxy solar resource. This impacts the incremental ELCC values relative to analysis based on additions of the proxy resource. See LC 73_REC DR

obligations, the improved modeling of dispatchable resources, the statistical consideration of probabilistic weeks instead of independent hourly probability distributions, and the perfect capacity reporting convention). As discussed on page 33 of the IRP Update, the change to reporting in terms of perfect capacity, all else held constant, results in a decrease to all ELCC values. However, this is offset by a corresponding increase to the cost of capacity.[3]

The factors discussed in the previous paragraph (as well as the additional solar resources in the Baseline Portfolio) also impacted the ELCC values for wind resources and may very minorly impact the SCCT ELCC values. PGE notes that the dominant factor in the decrease of the ELCC value of the SCCT is likely the change to reporting convention.

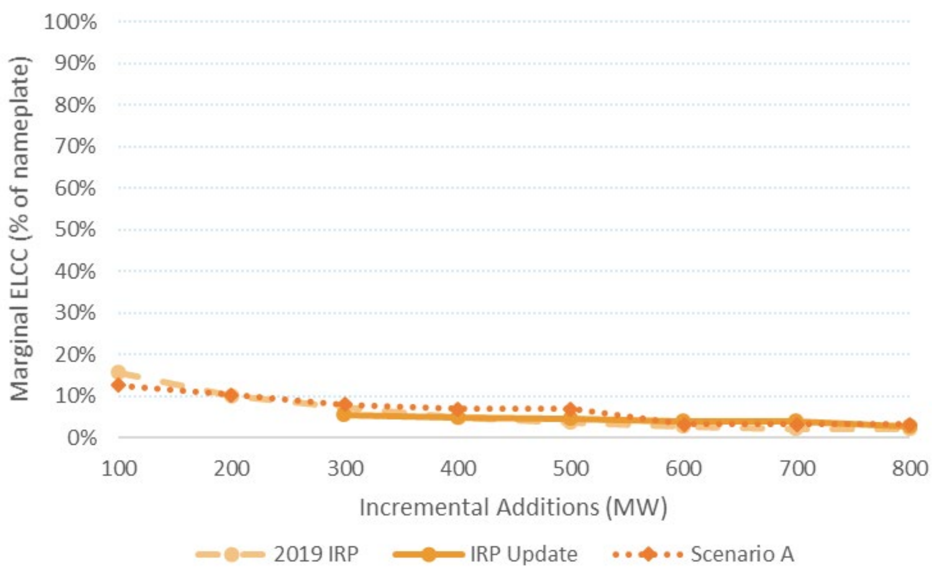
In order to provide some additional insight into the impact of the additional solar resources in the Baseline Portfolio, PGE prepared analysis examining a scenario based on the 2019 IRP Update Sequoia model with 200 MW of solar resources removed from the Baseline Portfolio to approximate the quantity of solar in the 2019 IRP study. **Figure 1** compares the ELCC values for solar from the 2019 IRP and the IRP Update with the scenario (labeled Scenario A in the figure).[4] The figure aligns the ELCC values based on the approximate quantity of solar resources in each study. The scenario showed a similar pattern to the 2019 IRP, with a higher initial ELCC value for solar than the IRP Update (as expected due to a reduction of solar in the portfolio compared to the IRP Update), and a declining value for the next increments. There was little change to the ELCC values for Gorge Wind and the SCCT compared to the IRP Update (26% and 95.2% in Scenario A compared to 25% and 95.5% in the IRP Update).

026_Attach_A_CONF. LC 73_REC DR 025_Attach_A_CONF is protected information subject to Protective Order No. 19-186.

[3] See IRP Update Section 5.4 – Cost of Capacity (page 50) for more detail.

[4] For this scenario, 161 MW of the first GEAR resource and 39 MW of the Community Solar program were removed.

Figure 1. Solar ELCC Comparison



As discussed previously, the capacity need reporting convention in the IRP Update (and Scenario A in Figure 1) differs from the 2019 IRP. It is important to note that when converting capacity contribution MW values to $/kW-yr values, the net cost of capacity should be based on the same reporting convention as the ELCC values.

PGE opted to run a test scenario in Sequoia, rather than attempting to run the RECAP model, because Sequoia is much less time- and resource-intensive. The Sequoia ELCC runs for the IRP Update took approximately 20 hours to complete, not including pre- and post-processing work and given optimal server conditions (e.g., no other users, no IT issues). This was a substantial process improvement compared to RECAP, which to complete the same level of work, would have required substantially more time and many manual steps of file transfer, outboard processing, and necessary double checking that those steps occurred correctly. Further, resolving differences due to changing factors with impacts that are less than 1 MW is not practical given model resolution.[5]

[5] Additionally, in order to account for portfolio effects, an analysis to attribute impacts to individual factors may involve preparing more model runs than the number of factors. For example, if examining just three factors, four to six model runs may be needed in addition to the base run.

Attachment D

PGE Response to REC Data Request No. 028

March 8, 2021

TO: Irion Sanger
Renewable Energy Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to REC Data Request No. 028
Dated February 22, 2021

Request:

Please identify differences to the QF resource portfolios considered for the 2019 IRP Plan Updated Needs Assessment and the IRP Update, including but not limited to changes to the nameplate capacities, resource types, and estimated commercial operation dates.

Response:

PGE objects to this request to the extent that it is vague, overly broad, unduly burdensome, and requests new analysis. Subject to and without waiving these objections, PGE responds as follows:

PGE interprets this request to seek information about the differences between the November 2019 Needs Assessment and the 2019 IRP Update snapshots for executed QF contracts and the projects actively progressing toward QF contract execution.[1]

PGE has not performed the analysis requested. The attachments listed below provide information about the QF contracts and projects as of the respective snapshot dates. The following attachments contain protected information and are subject to Protective Order No. 19-186: LC 73_REC DR 028_Attach_B_CONF, LC 73_REC DR 028_Attach_C_CONF, LC 73_REC DR 028_Attach_E_CONF, LC 73_REC DR 028_Attach_F_CONF.

2019 IRP Update	
Executed QF Contracts	• **LC 73_REC DR 028_Attach_A** • **LC 73_REC DR 028_Attach_B_CONF**
Projects actively progressing toward QF contracts	• **LC 73_REC DR 028_Attach_C_CONF**

[1] The projects actively progressing toward QF contract execution were included in the High QF sensitivities.

November 2019 Needs Assessment	
Executed QF Contracts	• **LC 73_REC DR 028_Attach_D** • **LC 73_REC DR 028_Attach_E_CONF**
Project actively progressing toward QF contracts	• **LC 73_REC DR 028_Attach_F_CONF**

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

Project Name	PPA Execution Date	Resource Type	Nameplate Capacity	Actual COD	Contract COD	Type of PPA	PPA Expiration Date
Coffin Butte	7/2/2012	Biogas	5.66	10/1/2012	10/1/2012	Standard	9/30/2027
Evergreen BioPower	5/31/2017	Biomass	10	2/1/2018	1/1/2018	Standard	5/31/2032
JC Biomethane	12/9/2011	Biogas	1.6	9/26/2013	7/31/2012	Standard	12/9/2031
OM Power 1	6/21/2016	Geothermal	10		6/1/2020	Standard	6/21/2036
Falls Creek Hydro	2/19/2019	Hydro	4.1		1/1/2020	Standard	2/1/2034
Middle Fork Irrigation District Unit 1 and Unit 2	4/2/2020	Hydro	2.80	Commercial operat	1/1/2022	Standard	12/31/2036
Minikahda Hydropower Co.	2/14/2014	Hydro	0.2	2/14/2014	2/14/2014	Standard	2/20/2029
Tualatin Valley Water District	4/1/2013	Hydro	0.11	4/1/2013	4/1/2013	Standard	3/31/2028
Von Family Limited Partnership	2/14/2014	Hydro	0.2	2/14/2014	2/14/2014	Standard	2/19/2029
Alfalfa Solar	6/26/2016	Solar	10		6/26/2019	Standard	6/26/2035
Alkali	8/26/2016	Solar	10		7/31/2019	Standard	7/31/2032
AM - West Silverton	4/19/2018	Solar	2.97		12/2/2019	Standard	12/1/2034
Amity Solar	5/20/2016	Solar	4		12/31/2019	Standard	5/20/2036
Ashcroft Solar	6/4/2018	Solar	2.25		9/30/2019	Standard	9/30/2039
Ballston Solar	5/2/2016	Solar	2.2	12/18/2018	8/31/2018	Standard	5/2/2036
Big Horn	9/17/2019	Solar	2.2		5/1/2020	Standard	8/13/2037
Blue Marmot IX	6/23/2020	Solar	10		12/7/2022	Standard	6/22/2038
Blue Marmot V	6/23/2020	Solar	10		9/27/2022	Standard	6/22/2038
Blue Marmot VI	6/23/2020	Solar	10		10/13/2022	Standard	6/22/2038
Blue Marmot VII	6/23/2020	Solar	10		11/2/2022	Standard	6/22/2038
Blue Marmot VIII	6/23/2020	Solar	10		11/23/2022	Standard	6/22/2038
Boring Solar	1/25/2016	Solar	2.2	4/3/2019	1/31/2019	Standard	1/25/2036
Brightwood Solar	3/1/2017	Solar	10		11/30/2021	Standard	2/1/2037
Bristol Solar	4/19/2018	Solar	3		12/2/2019	Standard	12/1/2034
Brush College Solar	5/25/2018	Solar	2		12/1/2019	Standard	3/1/2038
Brush Creek Solar	6/23/2017	Solar	2.2	5/15/2020	4/5/2019	Standard	6/23/2037
Butler Solar	1/25/2016	Solar	4.0		5/29/2020	Standard	1/25/2036
Case Creek Solar	6/22/2016	Solar	2.2	10/29/2019	5/5/2019	Standard	6/20/2036
Connley Solar	5/21/2019	Solar	10		12/1/2021	Standard	12/1/2041
Coolmine Solar	4/15/2020	Solar	1.98		2/2/2023	Standard	2/1/2043
Cow Creek Solar	6/4/2018	Solar	1.75		2/1/2020	Standard	2/1/2040
Day Hill Solar	11/10/2016	Solar	2.2		7/14/2019	Standard	9/7/2036
DB - Bull Run	4/19/2018	Solar	2.565		12/2/2019	Standard	12/1/2034
DC - Donald	4/19/2018	Solar	2.16		12/2/2019	Standard	12/1/2034
Delaney Solar	12/27/2017	Solar	2.5		10/31/2020	Standard	12/26/2032
DF - West Eagle Creek	4/19/2018	Solar	2.79		12/2/2019	Standard	12/1/2034
Domaine Drouhin	4/5/2013	Solar	0.094	4/5/2013	4/5/2013	Standard	4/15/2028
Drift Creek	1/25/2016	Solar	2.2	5/15/2020	4/1/2019	Standard	1/25/2036
Dryland Solar	4/19/2018	Solar	2.5		12/1/2019	Standard	10/31/2039
Dublin Solar	4/15/2020	Solar	2.97		2/2/2023	Standard	2/1/2043
Duus Solar	5/20/2016	Solar	10	2/6/2020	12/31/2019	Standard	5/20/2036
Eagle Creek Solar	12/27/2017	Solar	5		10/31/2020	Standard	12/26/2032
Eola Solar	1/29/2018	Solar	2.2		1/31/2020	Standard	11/30/2038
Fairview Solar	4/19/2018	Solar	3		12/2/2019	Standard	12/1/2034
Firwood Solar	5/20/2016	Solar	10	1/27/2020	12/31/2019	Standard	5/20/2036
Fort Rock Solar I	4/27/2016	Solar	10	3/11/2020	4/27/2019	Standard	4/27/2035
Fort Rock Solar II	4/27/2016	Solar	10		4/27/2019	Standard	4/27/2035
Fort Rock Solar IV	6/26/2016	Solar	10		6/26/2019	Standard	6/26/2035
Greenpark Solar	5/8/2018	Solar	1.26		12/2/2019	Standard	12/1/2034
Harney Solar I	6/27/2016	Solar	10		6/27/2019	Standard	6/27/2035
Hogan Solar	4/27/2020	Solar	2.565		2/2/2023	Standard	2/1/2043
Kale Patch Solar	5/10/2017	Solar	2.2	10/31/2019	7/31/2019	Standard	5/10/2037
KT - Molalla	4/19/2018	Solar	2.97		12/2/2019	Standard	12/1/2034
Labish Solar	12/1/2016	Solar	2.2	12/18/2018	8/31/2018	Standard	11/10/2036
Lakeview	7/15/2015	Solar	10	1/6/2020	5/1/2018	Standard	7/15/2035
Liberal Solar	12/27/2017	Solar	10		10/31/2020	Standard	12/26/2032
Milford Solar	4/19/2018	Solar	2.97		12/2/2019	Standard	12/1/2034
Minke Solar	9/17/2019	Solar	2.2		5/1/2020	Standard	8/13/2037
Mountain Meadow Solar	5/25/2018	Solar	2.5		12/1/2019	Standard	3/1/2038
NorWest Energy 14	7/28/2015	Solar	2.2	2/8/2018	12/31/2017	Standard	12/31/2031
OE Solar 3	1/25/2016	Solar	10	9/7/2018	12/30/2018	Standard	12/30/2033
O'neil Creek Solar	6/10/2016	Solar	2.2	12/9/2019	3/24/2019	Standard	6/10/2036
Palmer Solar	6/21/2016	Solar	2.2		7/1/2019	Standard	6/21/2036
Parrott Creek Solar	6/28/2018	Solar	2		12/1/2019	Standard	11/1/2039
PG - West Sheridan	4/18/2018	Solar	3		12/2/2019	Standard	12/1/2034
Pika Solar	9/17/2019	Solar	2.2		5/1/2020	Standard	8/6/2037
Radio Solar	11/29/2018	Solar	2.5		12/31/2020	Standard	12/31/2040
Rafael Solar	6/21/2016	Solar	2.2	10/29/2019	6/30/2019	Standard	6/21/2036
Raven Loop	5/25/2018	Solar	2		12/1/2019	Standard	3/1/2038
Reed Solar	5/21/2019	Solar	2.2		12/1/2020	Standard	11/30/2040
Ridgeway Solar	6/4/2018	Solar	2.5		12/1/2019	Standard	11/1/2039
Riley Solar	6/27/2016	Solar	10		6/27/2019	Standard	6/27/2035
Rock Creek Solar	2/7/2018	Solar	2.2		12/31/2020	Standard	2/6/2033
Rock Garden	8/26/2016	Solar	10		7/31/2019	Standard	7/31/2032
SB - South Wilamina	4/19/2018	Solar	2.97		12/2/2019	Standard	12/1/2034
Sheep Solar	1/25/2016	Solar	2.2	2/8/2018	12/31/2017	Standard	1/25/2036

Existing and Proposed PURPA Qualified Facilities (QFs)
by Shawn Davis / Bruce True
03/22/2016

Project Name	PPA Execution Date	Resource Type	Nameplate Capacity	Actual COD	Contract COD	Type of PPA	PPA Expiration Date
Silverton Solar	1/25/2016	Solar	2.2	2/8/2018	12/31/2017	Standard	1/26/2036
South Burns Solar I	7/20/2016	Solar	10		7/20/2019	Standard	7/20/2035
SP Solar 1	7/28/2015	Solar	2.2	2/8/2018	12/31/2017	Standard	7/28/2035
SP Solar 5	7/28/2015	Solar	2.2	2/8/2018	12/31/2017	Standard	7/28/2035
SP Solar 6	7/28/2015	Solar	2.2	8/21/2018	12/31/2017	Standard	7/28/2035
SP Solar 7	7/28/2015	Solar	2.2	6/30/2018	12/31/2017	Standard	7/28/2035
SP Solar 8	7/28/2015	Solar	2.2	2/8/2018	12/31/2017	Standard	7/28/2035
SSD Clackamas 1	5/8/2018	Solar	4		10/5/2021	Standard	10/4/2036
SSD Clackamas 4	10/20/2017	Solar	2		4/1/2020	Standard	3/31/2035
SSD Clackamas 7	5/8/2018	Solar	2		4/1/2020	Standard	3/31/2035
SSD Marion 1	5/25/2018	Solar	2		4/1/2020	Standard	3/31/2035
SSD Marion 3	10/20/2017	Solar	2		4/1/2020	Standard	3/31/2035
SSD Marion 5	5/8/2018	Solar	2		4/1/2020	Standard	3/31/2035
SSD Marion 6	5/8/2018	Solar	2		4/1/2020	Standard	3/31/2035
St Louis Solar	6/10/2016	Solar	2.2	4/6/2020	2/10/2019	Standard	6/9/2036
Starbuck Properties	11/2/2010	Solar	0.025	1/1/2011	1/17/2011	Standard	11/2/2030
Stark Solar (Solar Star Oregon)	6/2/2017	Solar	10		12/31/2019	Standard	12/30/2034
Starlight Solar	5/20/2016	Solar	4		12/31/2019	Standard	5/20/2036
Starvation Solar	1/25/2016	Solar	10	12/27/2019	1/25/2019	Standard	1/25/2035
Steel Bridge Solar	2/19/2014	Solar	2.5	2/18/2016	8/19/2015	Standard	2/19/2034
Stilorgan Solar	1/17/2020	Solar	1.53		11/2/2022	Standard	11/1/2042
Stringtown Solar	5/20/2016	Solar	4		12/31/2019	Standard	5/20/2036

Novemer 2019 Needs Assessment

QF Snapshot: executed standard contracts and those referred to in OPUC Order No. 19-322.

Plant Name	Resource Type	Type of PPA	Nameplate Capacity	PPA Execute Date	Actual COD	Contract COD	PPA Expiration Date	Nov 2019 Needs Assessment Estimated Start Date	Nov 2019 Needs Assessment Estimated End Date	Nov 2019 Needs Assessment Estimated Annual MWa
Coffin Butte	Biogas	Standard	5.66	7/2/2012	10/1/2012	10/1/2012	9/30/2027	10/1/2012	9/30/2027	5.4
Evergreen BioPo	Biomass	Standard	10	5/31/2017	1/17/2018	1/1/2018	5/31/2032	2/1/2018	5/31/2032	5.2
JC Biomethane	Biogas	Standard	1.6	12/9/2011	9/26/2013	7/31/2012	12/9/2031	9/26/2013	12/9/2031	1.4
OM Power 1	Geothermal	Standard	10	6/21/2016		6/1/2020	6/21/2036	6/1/2020	6/21/2036	8.3
Falls Creek Hydr	Hydro	Standard	4.1	2/19/2019		1/1/2020	2/1/2034	1/1/2020	2/1/2034	1.8
Minikahda Hydr	Hydro	Standard	0.2	2/14/2014	2/14/2014	2/14/2014	2/20/2029	2/14/2014	2/20/2029	0.03
Tualatin Valley \	Hydro	Standard	0.112	4/1/2013	4/1/2013	4/1/2013	3/31/2028	4/1/2013	3/31/2028	0.02
Von Family Limi	Hydro	Standard	0.2	2/14/2014	2/14/2014	2/14/2014	2/19/2029	2/14/2014	2/19/2029	0.03
Alfalfa Solar	Solar	Standard	10	6/26/2016		6/26/2019	6/26/2035	6/26/2019	6/26/2035	2.3
Alkali	Solar	Standard	10	8/26/2016		7/31/2019	7/31/2032	7/31/2019	7/31/2032	2.2
AM - West Silve	Solar	Standard	2.97	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Amity Solar	Solar	Standard	4	5/20/2016		12/31/2019	5/20/2036	12/31/2019	5/20/2036	0.9
Ashcroft Solar	Solar	Standard	2.25	6/4/2018		9/30/2019	9/30/2039	9/30/2019	9/30/2039	0.5
Ashfield Solar	Solar	Standard	3	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Ballston Solar	Solar	Standard	2.2	5/2/2016	12/18/2018	8/31/2018	5/2/2036	12/18/2018	5/2/2036	0.3
Belvedere Solar	Solar	Standard	2.97	9/9/2019		5/2/2022	5/1/2042	5/2/2022	5/1/2042	0.6
Big Horn	Solar	Standard	2.2	9/17/2019		5/1/2020	8/13/2037	5/1/2020	8/13/2037	0.5
Black Forest Sol	Solar	Standard	1.26	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.2
Blue Marmot IX	Solar	Standard	10			3/31/2020	3/1/2037	3/31/2020	3/1/2037	2.5
Blue Marmot V	Solar	Standard	10			11/30/2019	9/8/2036	11/30/2019	9/8/2036	2.5
Blue Marmot VI	Solar	Standard	10			11/30/2019	9/8/2036	11/30/2019	9/8/2036	2.5
Blue Marmot VII	Solar	Standard	10			3/31/2020	3/1/2037	3/31/2020	3/1/2037	2.5
Blue Marmot VII	Solar	Standard	10			3/31/2020	3/31/2038	3/31/2020	3/31/2038	2.5
Boring Solar	Solar	Standard	2.2	1/25/2016	4/3/2019	1/31/2019	1/25/2036	4/3/2019	1/25/2036	0.2
Bridgeport Solar	Solar	Standard	7	5/20/2016		12/31/2019	5/20/2036	12/31/2019	5/20/2036	1.7
Brightwood Sola	Solar	Standard	10	3/1/2017		10/30/2020	2/1/2037	10/30/2020	2/1/2037	2.0
Bristol Solar	Solar	Standard	3	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Brush College Sc	Solar	Standard	2	5/25/2018		12/1/2019	3/1/2038	12/1/2019	3/1/2038	0.4
Brush Creek Sol	Solar	Standard	2.2	6/23/2017		4/5/2019	6/23/2037	4/5/2019	6/23/2037	0.3
Buckner Creek S	Solar	Standard	2.5	11/29/2018		12/1/2020	12/1/2040	12/1/2020	12/1/2040	0.4
Butler Solar	Solar	Standard	4	1/25/2016		5/29/2020	1/25/2036	5/29/2020	1/25/2036	0.9
Carnes Creek So	Solar	Standard	2.5	8/31/2018		11/1/2020	11/1/2040	11/1/2020	11/1/2040	0.5
Case Creek Sola	Solar	Standard	2.2	6/22/2016		5/5/2019	6/20/2036	5/5/2019	6/20/2036	0.3
Clayfield Solar	Solar	Standard	2.565	11/7/2018		7/2/2021	7/1/2041	7/2/2021	7/1/2041	0.5
Connley Solar	Solar	Standard	10	5/21/2019		12/1/2021	12/1/2041	12/1/2021	12/1/2041	3.0
Cosper Creek So	Solar	Standard	2.5	4/19/2018		12/1/2019	11/1/2039	12/1/2019	11/1/2039	0.5
Cow Creek Solar	Solar	Standard	1.75	6/4/2018		2/1/2020	2/1/2040	2/1/2020	2/1/2040	0.4
Day Hill Solar	Solar	Standard	2.2	11/10/2016		7/14/2019	9/7/2036	7/14/2019	9/7/2036	0.2
Dayton Solar I	Solar	Standard	10	1/25/2016		1/25/2019	1/25/2035	1/25/2019	1/25/2035	1.8
DB - Bull Run	Solar	Standard	2.565	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.4
DC - Donald	Solar	Standard	2.16	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.4
DD - Molalla	Solar	Standard	3	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Delaney Solar	Solar	Standard	2.5	12/27/2017		10/31/2020	12/26/2032	10/31/2020	12/26/2032	0.5
DF - West Eagle	Solar	Standard	2.79	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Domaine Drouhi	Solar	Standard	0.094	4/5/2013	4/5/2013	4/5/2013	4/15/2028	4/5/2013	4/15/2028	1.1E-05
Drift Creek	Solar	Standard	2.2	1/25/2016		4/1/2019	1/25/2036	4/1/2019	1/25/2036	0.4
Dryland Solar	Solar	Standard	2.5	4/19/2018		12/1/2019	10/31/2039	12/1/2019	10/31/2039	0.5
Dunn Rd Solar	Solar	Standard	1.85	4/19/2018		10/31/2019	10/31/2039	10/31/2019	10/31/2039	0.3
Duus Solar	Solar	Standard	10	5/20/2016		12/31/2019	5/20/2036	12/31/2019	5/20/2036	2.1
Eagle Creek Sola	Solar	Standard	5	12/27/2017		10/31/2020	12/26/2032	10/31/2020	12/26/2032	1.0
Eola Solar	Solar	Standard	2.2	1/29/2018		1/31/2020	11/30/2038	1/31/2020	11/30/2038	0.4

Fairview Solar	Solar	Standard	3	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Firwood Solar	Solar	Standard	10	5/20/2016		12/31/2019	5/20/2036	12/31/2019	5/20/2036	2.3
Fort Rock Solar I	Solar	Standard	10	4/27/2016		4/27/2019	4/27/2035	4/27/2019	4/27/2035	2.2
Fort Rock Solar I	Solar	Standard	10	4/27/2016		4/27/2019	4/27/2035	4/27/2019	4/27/2035	2.2
Fort Rock Solar I	Solar	Standard	10	6/26/2016		6/26/2019	6/26/2035	6/26/2019	6/26/2035	2.3
Fossil Lake	Solar	Standard	10	4/29/2015		11/30/2017	4/29/2035	11/30/2017	4/29/2035	2.6
Fruitland Creek	Solar	Standard	1.75	5/25/2018		12/1/2019	3/1/2038	12/1/2019	3/1/2038	0.3
Greenpark Solar	Solar	Standard	1.26	5/8/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.2
Gun Club Solar	Solar	Standard	2.5	5/8/2018		12/1/2019	12/1/2039	12/1/2019	12/1/2039	0.5
Harney Solar I	Solar	Standard	10	6/27/2016		6/27/2019	6/27/2035	6/27/2019	6/27/2035	2.2
Kaiser Creek Sola	Solar	Standard	2	6/4/2018		12/1/2019	11/1/2039	12/1/2019	11/1/2039	0.5
Kale Patch Solar	Solar	Standard	2.2	5/10/2017		7/31/2019	5/10/2037	7/31/2019	5/10/2037	0.3
Kensington Solar	Solar	Standard	0.99	5/8/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.2
Kerry Solar	Solar	Standard	2.97	5/8/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
KT - Molalla	Solar	Standard	2.97	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Labish Solar	Solar	Standard	2.2	12/1/2016	12/18/2018	8/31/2018	11/10/2036	12/18/2018	11/10/2036	0.3
Lakeview	Solar	Standard	10	7/15/2015		5/1/2018	7/15/2035	5/1/2018	7/15/2035	2.8
Liberal Solar	Solar	Standard	10	12/27/2017		10/31/2020	12/26/2032	10/31/2020	12/26/2032	2.0
Manchester Sola	Solar	Standard	1.8	9/26/2018		7/2/2021	7/1/2041	7/2/2021	7/1/2041	0.4
Marquam Creek	Solar	Standard	2	2/9/2019		12/1/2020	11/1/2040	12/1/2020	11/1/2040	0.3
Milford Solar	Solar	Standard	2.97	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Minke Solar	Solar	Standard	2.2	9/17/2019		5/1/2020	8/13/2037	5/1/2020	8/13/2037	0.4
Mountain Mead	Solar	Standard	2.5	5/25/2018		12/1/2019	3/1/2038	12/1/2019	3/1/2038	0.5
Mt Hope Solar	Solar	Standard	2.5	5/25/2018		12/1/2019	3/1/2038	12/1/2019	3/1/2038	0.5
NorWest Energy	Solar	Standard	2.2	7/28/2015	2/8/2018	12/31/2017	12/31/2031	2/8/2018	12/31/2031	0.3
OE Solar 3 (Wy'E	Solar	Standard	10	1/25/2016	9/7/2018	12/30/2018	12/30/2033	9/7/2018	12/30/2033	2.6
O'neil Creek Sola	Solar	Standard	2.2	6/10/2016		3/24/2019	6/10/2036	3/24/2019	6/10/2036	0.2
Palmer Solar	Solar	Standard	2.2	6/21/2016		7/1/2019	6/21/2036	7/1/2019	6/21/2036	0.3
Parrott Creek So	Solar	Standard	2	6/28/2018		12/1/2019	11/1/2039	12/1/2019	11/1/2039	0.5
PG - West Sheric	Solar	Standard	3	4/18/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Pika Solar	Solar	Standard	2.2	9/17/2019		5/1/2020	8/6/2037	5/1/2020	8/6/2037	0.4
Radio Solar	Solar	Standard	2.5	11/29/2018		12/31/2020	12/31/2040	12/31/2020	12/31/2040	0.4
Rafael Solar	Solar	Standard	2.2	6/21/2016		6/30/2019	6/21/2036	6/30/2019	6/21/2036	0.2
Raven Loop	Solar	Standard	2	5/25/2018		12/1/2019	3/1/2038	12/1/2019	3/1/2038	0.4
Reed Solar	Solar	########	2.2	5/21/2019		12/1/2020	11/30/2040	12/1/2020	11/30/2040	0.4
Ridgeway Solar	Solar	Standard	2.5	6/4/2018		12/1/2019	11/1/2039	12/1/2019	11/1/2039	0.6
Riley Solar	Solar	Standard	10	6/27/2016		6/27/2019	6/27/2035	6/27/2019	6/27/2035	2.3
River Valley Sola	Solar	Standard	2	5/25/2018		12/1/2019	3/1/2038	12/1/2019	3/1/2038	0.4
Rock Creek Solar	Solar	Standard	2.2	2/7/2018		12/31/2020	2/6/2033	12/31/2020	2/6/2033	0.5
Rock Garden	Solar	Standard	10	8/26/2016		7/31/2019	7/31/2032	7/31/2019	7/31/2032	2.2
Sandy River Sola	Solar	Standard	1.85	5/25/2018		12/1/2019	3/1/2038	12/1/2019	3/1/2038	0.4
SB - South Wilan	Solar	Standard	2.97	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Sesqui-C Solar	Solar	Standard	2.5	11/29/2018		12/31/2020	12/31/2040	12/31/2020	12/31/2040	0.4
Sheep Solar	Solar	Standard	2.2	1/25/2016	2/8/2018	12/31/2017	1/25/2036	2/8/2018	1/25/2036	0.5
Silverton Solar	Solar	Standard	2.2	1/25/2016	2/8/2018	12/31/2017	1/26/2036	2/8/2018	1/26/2036	0.4
South Burns Sola	Solar	Standard	10	7/20/2016		7/20/2019	7/20/2035	7/20/2019	7/20/2035	2.2
SP Solar 1 (Inter	Solar	Standard	2.2	7/28/2015	2/8/2018	12/31/2017	7/28/2035	2/8/2018	7/28/2035	0.3
SP Solar 2 (Goos	Solar	Standard	2.2	7/28/2015		12/31/2017	7/28/2035	12/31/2017	7/28/2035	0.3
SP Solar 5 (Mill C	Solar	Standard	2.2	7/28/2015	2/8/2018	12/31/2017	7/28/2035	2/8/2018	7/28/2035	0.3
SP Solar 6 (Colto	Solar	Standard	2.2	7/28/2015	8/21/2018	12/31/2017	7/28/2035	8/21/2018	7/28/2035	0.3
SP Solar 7 (Dayto	Solar	Standard	2.2	7/28/2015	6/30/2018	12/31/2017	7/28/2035	6/30/2018	7/28/2035	0.3
SP Solar 8 (Valley	Solar	Standard	2.2	7/28/2015	2/8/2018	12/31/2017	7/28/2035	2/8/2018	7/28/2035	0.3
SSD Clackamas 1	Solar	Standard	4	5/8/2018		10/5/2021	10/4/2036	10/5/2021	10/4/2036	0.9
SSD Clackamas 4	Solar	Standard	2	10/20/2017		4/1/2020	3/31/2035	4/1/2020	3/31/2035	0.5
SSD Clackamas 7	Solar	Standard	2	5/8/2018		4/1/2020	3/31/2035	4/1/2020	3/31/2035	0.5
SSD Marion 1	Solar	Standard	2	5/25/2018		4/1/2020	3/31/2035	4/1/2020	3/31/2035	0.5
SSD Marion 3	Solar	Standard	2	10/20/2017		4/1/2020	3/31/2035	4/1/2020	3/31/2035	0.5
SSD Marion 5	Solar	Standard	2	5/8/2018		4/1/2020	3/31/2035	4/1/2020	3/31/2035	0.5
SSD Marion 6	Solar	Standard	2	5/8/2018		4/1/2020	3/31/2035	4/1/2020	3/31/2035	0.5
St Louis Solar	Solar	Standard	2.2	6/10/2016		2/10/2019	6/9/2036	2/10/2019	6/9/2036	0.2
Starbuck Proper	Solar	Standard	0.025	11/2/2010	1/1/2011	1/17/2011	11/2/2030	1/1/2011	11/2/2030	0.003

Stark Solar (Sola	Solar	Standard	10	6/2/2017		12/31/2019	12/30/2034	12/31/2019	12/30/2034	2.8
Starlight Solar	Solar	Standard	4	5/20/2016		12/31/2019	5/20/2036	12/31/2019	5/20/2036	0.9
Starvation Solar	Solar	Standard	10	1/25/2016		1/25/2019	1/25/2035	1/25/2019	1/25/2035	2.2
Steel Bridge Sola	Solar	Standard	2.5	2/19/2014	2/18/2016	8/19/2015	2/19/2034	2/18/2016	2/19/2034	0.4
Stringtown Solar	Solar	Standard	4	5/20/2016		12/31/2019	5/20/2036	12/31/2019	5/20/2036	0.9
SulusSolar6	Solar	Standard	3	4/19/2018		12/2/2019	12/1/2034	12/2/2019	12/1/2034	0.5
Suntex Solar	Solar	Standard	10	5/16/2016		7/20/2019	6/1/2035	7/20/2019	6/1/2035	2.2
Thomas Creek S	Solar	Standard	2.2	5/31/2017		2/1/2019	5/31/2037	2/1/2019	5/31/2037	0.3
Tickle Creek Sola	Solar	Standard	1.85	8/23/2017		1/31/2019	8/22/2037	1/31/2019	8/22/2037	0.2
Townsend Solar	Solar	Standard	2.25	6/4/2018		9/30/2019	9/30/2039	9/30/2019	9/30/2039	0.4
Tygh Valley Sola	Solar	Standard	10	1/25/2016		1/25/2019	1/25/2035	1/25/2019	1/25/2035	2.1
Volcano Solar	Solar	Standard	0.75	10/18/2017	7/17/2019	3/1/2018	10/18/2037	7/17/2019	10/18/2037	0.1
Waconda Solar	Solar	Standard	2.25	6/4/2018		2/1/2020	4/1/2038	2/1/2020	4/1/2038	0.5
Walker Creek So	Solar	Standard	2.5	2/9/2019		12/1/2020	11/1/2040	12/1/2020	11/1/2040	0.4
Wasco Solar 1	Solar	Standard	10	1/25/2016		1/25/2019	1/25/2035	1/25/2019	1/25/2035	2.1
Waterford Solar	Solar	Standard	2.565	8/27/2019		5/2/2022	5/1/2042	5/2/2022	5/1/2042	0.5
West Hines Sola	Solar	Standard	10	7/20/2016		7/20/2019	7/20/2035	7/20/2019	7/20/2035	2.2
Willamina Mill S	Solar	Standard	2.2	6/21/2016		8/14/2019	6/21/2036	8/14/2019	6/21/2036	0.3
Williams Acres S	Solar	Standard	2.5	6/4/2018		12/1/2019	12/1/2039	12/1/2019	12/1/2039	0.5
Yamhill Creek Sc	Solar	Standard	2.2	5/31/2017		4/30/2018	5/31/2037	4/30/2018	5/31/2037	0.3
Zena Solar	Solar	Standard	2.5	6/4/2018		12/1/2019	12/1/2039	12/1/2019	12/1/2039	0.5
PaTu Wind	Wind	Standard	9	4/29/2010	12/1/2010	5/31/2011	5/31/2031	12/1/2010	5/31/2031	3.0

Attachment E

PGE Response to REC Data Request No. 025

March 3, 2021

TO: Irion Sanger
Renewable Energy Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to REC Data Request No. 025
Dated February 22, 2021

Request:

Please reference PGE's IRP Update at page 39, which states that "As discussed in Section 2.3.7, when analysis was conducted for this IRP Update, the Baseline Portfolio included approximately 93 MW of resources for the Community Solar program and the executed 162 MW resource for the first tranche of the GEAR program. At that time, an additional 138 MW of GEAR was approved, but resource procurement had not been finalized."

a. Is it PGE's position that procurement of approximately 93 MW of resources for the Community Solar program had been "finalized" as that word is used in the quoted language above?

b. Did PGE conduct a sensitivity for any of the approximately 93 MW of resources for the Community Solar program? If so, please provide the sensitivity(ies). If not, please explain PGE's decision not to conduct a sensitivity.

c. Please provide the marginal ELCC value for solar resources using both the RECAP and Sequoia model and the estimated impact on avoided cost pricing for solar resources if 0%, 25%, 50%, 75%, or 100% of the approximately 93 MW of resources for the Community Solar program do not come online: 1) on time; 2) within one year of the expected dates; 3) within three years of the expected dates; and 4) at any time.

Response:

PGE objects to this request to the extent that it is overly broad, unduly burdensome, calls for speculation, requests new analysis, and is vague. Subject to and without waiving these objections, PGE responds as follows:

The Community Solar program was launched in January 2020 with the first 46.57 MW in the interim offering. Of the 46.57-MW interim offering, the general capacity is filled,[1] and 11.6 MW of carve-out capacity remains.[2]

In May of 2020, a Community Solar Settlement Agreement was reached with parties including developers with executed PURPA Qualifying Facility (QF) contracts and approved by the Commission. The 2019 IRP Update includes both the addition of the Community Solar program to the Baseline Portfolio and the removal of the QF contracts anticipated to be terminated due to the Community Solar Settlement Agreement. Please also see PGE's response to REC Data Request No. 019.

A. No. At the time of the snapshot, resource procurement for the Community Solar program had not been finalized. However, given the status of the program and the approved Community Solar Settlement Agreement, PGE found inclusion of the program and the anticipated settlement terminations in the IRP Update to be appropriate.

B. No. The 2019 IRP Update did not include a sensitivity of the Community Solar Program because the program is included in the Baseline Portfolio.

C. PGE has not conducted the analysis requested, but notes the following in response to items 1 through 4 of this request:

   In the IRP Update, 50 percent of the Community Solar program was assumed to be online by January 1, 2022 and the remaining 50 percent was assumed to be online on January 1, 2023. If the ELCC study were modified to change these dates to any date on or before January 1, 2025, there would be no impact on the ELCC study.[3] To the extent that a portion or all of the program were assumed to have a start date after January 1, 2025, PGE would anticipate impacts to the ELCC study values of all resources, with likely some increase to the value for the first increment of solar resources. However, PGE also notes that as mentioned above, when the Baseline Portfolio was updated to include Community Solar, the portfolio was also updated to remove executed QF contracts anticipated to be terminated at that time due to the Community Solar Settlement. If a scenario were to incorporate different assumptions regarding the Community Solar start date (or no start date for Community Solar) such a scenario may also require PGE to incorporate different assumptions regarding the QF contracts that were assumed to be terminated based on the Community Solar Settlement Agreement.

   In a hypothetical scenario that does not include any portion of the Community solar program, but still included the same assumption for anticipated QF contract terminations from the Community Solar Settlement Agreement, PGE estimates that the ELCC value for the first increment of solar resources from RECAP may be less than 10.2 percent (see

[1] Excluding the 0.96 MW of general capacity discussed in Commission Order No. 21-071, page 4.
[2] Carve-out projects include 360 kW and under projects and are led by a non-profit or public Project Manager. Please refer to Order No. 19-392, page 85.
[3] Aside from a very minor impact due to a shift in the solar degradation assumption for the Community Solar resource.

Table 18 of the 2019 IRP Update, page 64).[4] However, PGE does not find this scenario to be an appropriate assumption for long-term planning for several reasons including that it would not be based on the best available information at the time of analysis given the January 2020 launch of the Community Solar Program and the May 2020 Community Solar Settlement Agreement.

While this request seeks information about potential impacts of multiple scenarios that assume a smaller quantity of solar resources in the portfolio than in the IRP Update analysis, PGE notes that since the resource snapshot for the IRP Update, PGE has executed contracts for more than 138 MW of additional solar resources.

[4] The ELCC studies from the 2016 IRP through the 2019 IRP Update examined ELCC values for solar based on 100 MW increments. If a hypothetical scenario included the anticipated terminations from the Community Solar Settlement Agreement but did not include the Community Solar program, the increase to solar in the portfolio may be approximately 110 MW instead of 200 MW. Based on the 2019 IRP ELCC study, which found an ELCC value of 10.2 percent for the second 100 MW increment of solar resources, this scenario may result in an ELCC value less than 10.2 percent.

Attachment F

PGE Response to REC Data Request No. 019

March 2, 2021

TO: Irion Sanger
Renewable Energy Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to REC Data Request No. 019
Dated February 17, 2021

Request:

Please reference the 2019 IRP Update, which states that "Approximately 93 MW of Community Solar resources were included in the modeling of the Baseline Portfolio, with half of the Community Solar resources beginning in January 2022 and the second half beginning in January 2023."

a. On what basis is PGE projecting that "half of the [approximately 93 MW of] Community Solar resources [will] begin[] in January 2022"?
b. Order No. 19-438 approved an Interim Offering for the Community Solar Program in PGE's service territory of 46.57 MW, or 50% of PGE's initial capacity limit of 93.15 MW. On what basis is PGE included the full 93.15 MW in its Baseline Portfolio? On what date is PGE projecting that the Commission will open the additional 46.57 MW of space to new projects?
c. On what basis is PGE projecting that the "second half [will] begin[] in January 2023?

Response:

To clarify, in the IRP Update PGE did not state that we project specific beginning dates for either half of the Community Solar program, rather, we identified the modeling assumptions used in the IRP Update.

a. The Oregon Community Solar Program has a total capacity approved for PGE of approximately 93 MW. The interim offering is approximately half of the total capacity at 46.57 MW and was opened on January 21, 2020. The resource modeling period for the 2019 IRP Update starts in 2022 and so captures the impacts of the interim offering starting in 2022.
b. The interim offering is approximately half of the total capacity at 46.57 MW and was opened on January 21, 2020. The interim offering is described as the portion of the initial

program capacity tier to be launched using the current residential retail rate.[1] In PGE's service area, the general capacity for the Interim offering has already been filled. PGE does not project a specific launch date for the remainder of the Initial offering capacity. However, in discussions Staff has noted that interim activities will begin and could continue for up to 24 months before projects begin billing participants per rules proposed in the program implementation manual.[2] For modeling purposes, PGE included the second half of the initial offering beginning on January 1, 2023. PGE plans to revise our estimate as updated information from regulatory proceedings is available.

Furthermore, PGE notes the 2019 IRP Update includes both the addition of the Community Solar Program to the Baseline Portfolio and the removal of the QF contracts anticipated to be terminated at the time due to the Community Solar Settlement Agreement. The update does not result in duplicate views of specific projects projected to be Community Solar projects.

c. Please see response to part b.

[1] Please see Order 19-392, page 2 footnote 2.
[2] Please see UM 1930 Staff Report from October 4, 2019, page 26, 74, 76, 83.