March 10, 2021

Via Electronic Filing

Oregon Public Utility Commission
Attention: Filing Center
201 High Street, Suite 100
Post Office Box 1088
Salem, OR 97308-1088

Re: LC 73 PGE IRP Update Comments

Dear Commissioners:

NewSun Energy LLC (NewSun) provides these comments on Portland General Electric's (PGE's) Integrated Resource Plan (IRP) Update filed on January 29, 2021.

NewSun urges the Public Utility Commission (PUC or Commission) of Oregon to not acknowledge PGE's IRP Update. The proposed update serves no purpose, except to attempt to inappropriately reduce avoided cost prices for QFs, based on cherry-picked assumptions, which ignore both known bad inputs as well as other aspects that would lift prices.

The only updated items are inputs to PGE's Public Utility Regulatory Policies Act (PURPA) avoided cost prices that – that only operate in one direction – to significantly reduce avoided costs. Not only has PGE excluded other updates that would have increased avoided cost prices, such as PGE's own commitment to decarbonization, capacity shortfall issues (noted by Staff and PGE), but PGE proposes—in direct contradiction to evidence, other proceedings, and common sense, to *lower* the capacity contribution of solar, despite high correlations to their system's needs.

PGE does so based on an underlying reference solar project which was already incorrect and outdated (among other flaws) in 2019 when the 2019 IRP was approved, which has a 24.8% capacity factor assumption, when recent solar projects in the same area have ~**30%** capacity factors. *The ELCC should be going up not down*. By selectively—despite NewSun's public comments in IRP stakeholder process (and other) meetings—using outdated and unlikely design characteristics for the solar project in its capacity contribution analysis—PGE not only uses inappropriate assumptions, but compounds the declining ELCC contribution inappropriately, because it scales up a bad number—and thus adds insult to injury by proposing to then further lower the ELCCs, which in reality the number should be going up. This is in addition to using overstated assumptions on its solar pipeline status (e.g. including already dead projects), questionable weather data input, excess outage assumptions (solar PV does maintenance at night, and doesn't take any "planned outages" annually, much less 2% = 7.3 days/year propagated over decades; and due to modular nature does almost all maintenance without any outages). Scaling up bad assumptions only makes them worse, especially given how ELCC modeling works.

Further, PGE itself acknowledges the need to address climate change on a large scale and has publicly committed to 100% decarbonization by 2040, to be further engaged in its next full IRP. Which necessarily requires *substantial* additional generation procurement—thousands of additional MWs over the next decade plus, to have any chance of success—and which is entirely omitted from this highly selective update, despite clear, major corporate plans and public commitments to decarbonization. This selective omission is layered on top of significant concerns about a current and future capacity shortfall in the region, specifically 8 GW by 2030, and PGE's own notes about capacity needs.[1] In addition, Docket No. UM 2011 is investigating significant improvements to how the Commission and utilities approach capacity valuation. Once that docket reaches its conclusion, PGE can incorporate that new methodology into its next IRP and more holistically update its avoided cost prices.

PURPA projects play a key role in advancing progress towards decarbonization and resiliency goals by adding smaller increments of energy and capacity spread across the state in areas where resiliency is needed. Given the capacity, decarbonization, and resiliency needs, the Commission should not be endorsing changes which send inappropriate price signals that omit the value of contributions, and thereby shorting the market of related investment—and development and design approaches which are informed by these needs.

Finally, there is no urgency for this update at this time – unless it were to be correcting flawed inputs – as there is no evidence that PGE's currently effective avoided costs have resulted in too much QF contracting activity. In fact there have been zero power purchase agreements (PPAs) executed with new facilities since PGE's post-IRP avoided cost price update.

For all of these reasons, it simply does not make sense to acknowledge this update until a fuller and more robust analysis can be performed in the next full IRP considering decarbonization efforts, an updated capacity valuation methodology, and updated data inputs—absent other justifying new events (such as legislation) or remediation of major flaws.

Background

PGE's 2019 IRP was acknowledged at a public meeting on March 16, 2020 with updated avoided costs that became effective on May 20, 2020. Right around that same time on March 10, 2020, Governor Brown issued her Executive Order 20-04 directing state agencies to take actions within their discretion to address climate change, and only a few days later, the Governor issued her first of many orders addressing the COVID-19 pandemic. As PGE noted in its IRP Update, Oregonians across the state experienced significant turmoil over the last year as a result of climate wildfires and the pandemic-driven economic recession, among others. NewSun concurs with PGE that steps need to be taken in the near term to address climate change but also in a manner that benefits Oregonians who experience economic hardship and the destructive effects of wildfires.

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1 Energy+Environmental Economics, Resource Adequacy in the Pacific Northwest at 38 (March 2019) available at https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf.

NewSun disagrees with PGE, however, that the best way to solve this problem is to further stifle the development of Oregon projects, that are more likely to be located in Oregon, and can come online and begin reducing the utility's overall carbon emissions more quickly than utility-owned projects. PURPA projects have a unique opportunity to address climate change because they can come online much sooner, on more of a glide path towards greater decarbonization, and because they also offer resiliency benefits to Oregonians, by being closer to loads, and stimulate economic development within the state.

We also note as backdrop that NewSun's Jake Stephens raised several of the major flaws with PGE's underlying 2019 IRP solar modeling assumptions in public meetings, as directed to by PGE, including in December 2020. Thus PGE is fully aware of these flaws, yet chose to omit them or avoid remedying them, as they did other issues. Thus, the selectiveness involved by PGE here is intentional.

We note that PURPA requires paying full avoided costs. An update which excludes compensation for avoided capacity contributions, whether through improper solar modeling, or ignoring major planned major procurement, or ignoring outage costs and climate risks to which ratepayers are exposed, is not compliant with federal statute. The Commission should be directing PGE to include those aspects in its non-standard pricing modeling immediately.

Finally, we note that PGE has a history of attempts to selectively, inappropriately, and/or at inappropriate times attempt to reduce avoided costs through such misformed, selective, and/or misrepresentative approaches. The Commission should not reward such behavior either generally nor in this case – and perhaps should be considering penalties or other actions to discourage such utility actions, which face no consequences for the misplaced fire drills the put industry, staff, and stakeholders through.

Comments

Acknowledgment is not appropriate in this IRP Update because PGE is not altering its action plan and additional information and analysis in a full IRP is necessary.

A utility may request acknowledgment of changes to its IRP action plan in an IRP Update, but acknowledgment is not appropriate when additional information and broader analysis requires a full IRP.[2]

In this IRP Update, PGE does not propose any changes to its action plan but simply cherry-picks limited items that lowers solar avoided cost pricing by 9% (renewables) and 17% (without RECs), yet knowingly ignores other items and assumption/input corrections highly likely increase avoided cost updates, including items which it did not address despite concerns raised in PGE's IRP stakeholder process.

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2 Order 07-002 at 10; OAR 860-027-0400(8) ("The energy utility may request acknowledgment of changes, identified in its update, to the IRP action plan.")

1. The PUC Should Not Acknowledge Without Additional Analysis in a Full IRP

A more holistic analysis in a full IRP, or other comprehensive process that remediates flawed inputs, is necessary to account for other updates or trends that would have a positive effect on prices, mitigate PGE's perverse incentive to only update items that lower avoided costs, and to incorporate the PUC's anticipated new capacity valuation methodology.

a. PGE's ELCC Methodology Needs to Be Updated

The most significant update PGE makes in this IRP Update is its updated effective load carrying capacity (ELCC) calculation. This update has the effect of reducing the ELCC for solar projects from its current 15.8% to only 5.5% (as shown in Table 1).[3] However, before making such a drastic change to the solar ELCC value, both the methodology and the data underlying PGE's ELCC values need to be holistically updated.

Docket No. UM 2011 is an ongoing generic capacity investigation that aims to develop a methodology that will likely have broad applicability across a variety of contexts, including in the PURPA avoided cost context. This docket is likely to bring significant improvements to how PGE approaches the questions of "how much capacity a resource can provide" and "how to determine the value of that capacity." Among the issues being discussed in that docket, are how to address the very real threat of capacity shortfalls, the cost to ratepayers for such reliability failure events, and whether changes are needed to the current planning and operational assessments since current metrics have not foreseen the reliability failures seen in California and Texas (and close calls in the Northwest) over these last several months. The threat of these capacity/reliability outages is real, and now is not the time to be reducing capacity contribution values and further discouraging projects that could contribute to addressing this issue. Rather capacity contribution values should be increasing. Once a new methodology is determined, PGE can include that in its next full IRP in order to more holistically review the capacity question and its ELCC values in particular, rather than simply updating a few of the inputs on an ad hoc basis in an IRP Update.

In PGE's 2019 IRP, it developed incremental ELCC values based on the amount of that resource type in its portfolio, and PGE updated those values in this IRP Update.
As part of the baseline, PGE included all PURPA qualifying facility contracts executed at the time of its snapshot date. In this update, PGE updated that snapshot date to June 15, 2020.[4] It is not reasonable to assume that all PURPA contracts will reach commercial operation given the number of contracts that PGE terminated, and it is certainly not reasonable to assume that all qualifying facilities will reach commercial operation as of the scheduled commercial operation date (COD). Although PGE says it updated these QF contracts to include additional terminations and schedule updates, PGE has not done so in a reasonable manner. First, PGE's "schedule updates" simply assumed that every QF except one that has gone past its scheduled COD (50 in

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3 PGE IRP Update at 63 (Appendix D, Table 15) and 64 (Appendix E, Table 16); PGE IRP Update Supplemental Filing at 3 (Table 1); Attachment A (PGE Response to Renewable Energy Coalition Data Request No. 26).

4 PGE IRP Update at 30.

total), will come online on July 1, 2020.[5] Second, despite PGE explicitly acknowledging these concerns in its IRP Update, it makes no effort to reasonably forecast and include in its baseline an anticipated failure rate or delay metric.

PGE says the main driver of the change from the 15.8% ELCC to the 5.5% ELCC is the addition of approximately 200 MW of new solar resources to the baseline portfolio.[6] Had PGE stuck with the same incremental buckets in its 2019 IRP, the addition of 200 MW would have resulted in a solar ELCC of 7.2%, as showing int Table 1. Of this 200 MW, 93 MW of resources are attributed to the Community Solar Program which PGE says had not been finalized at the time of the snapshot.[7] Had those been excluded from the analysis, PGE says the increase of solar in the portfolio would have been approximately 110 MW rather than 200 MW.[8] Such an outcome would have placed PGE in the next lowest ELCC increment in Table 1 of 10.2%.

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%

Other updates PGE does not appear to have made include the characteristics and plant performance for the solar facility PGE used in its capacity contribution analysis. PGE used a project located in Christmas Valley Oregon which had an annual capacity factor of 24.8%, a DC/AC ratio of 1.3 and the hourly generation profile was developed based on a historical 7-year period.[9]

First, the seven-year period used to determine the generation profile needs to be updated and analyzed relative to larger weather history; PGE has not justified why this particular 7 year period was chosen, and why that approach was used instead of industry-typical longer data sets.

Second, and the design basis, particularly the DC/AC ratio, is inappropriately low, along with inappropriately high outage assumptions, all of which should be revised to reflect current design practices and not short the expected capacity contributions solar PV would provide with inappropriately low pricing and price signals. NewSun's recent experience building in Oregon's high desert shows that capacity factors should be around 30%, not 25% as PGE uses. DC/AC ratios for newer projects tend to be much higher, in the range of 1.5 or even more than that. Further, by increasing that ratio, the generator can round out production and firm up expected generation in key LOLP hot spots, summer evenings. The Christmas Valley project also had a planned outage rate of 2%,[10] which is unusual given that outages—which are rarely needed for

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5 Attachment A (PGE Response to Renewable Energy Coalition Data Request No. 28, Attachment A)
6 PGE IRP Update at 48; PGE IRP Update Supplemental Filing at 3.
7 Attachment A (PGE Response to Renewable Energy Coalition Data Request No. 25).
8 *Id.*
9 PGE 2019 IRP at 136, Table 5-7.
10 PGE IRP, External Study D at 21.

highly modular solar projects with numerous internal disconnect switches—and if needed would be scheduled at night when the solar project is not generating anyway.

NewSun participated in PGE's IRP stakeholder process and raised concerns over PGE's calculation of its solar ELCC values but does not see that PGE has addressed these concerns.

In light of these above considerations, the Commission should not acknowledge PGE's IRP Updates until after UM 2011 reaches its conclusion and without more in-depth, and more holistic analysis in the next full IRP.

b. PGE Ignored Other Factors That May Increase Avoided Cost Prices

PGE noted several items it is planning to consider in its next full IRP, many of which may result in increasing avoided cost prices, including:

- PGE's "new and ambitious climate goals" to decarbonize, which include a commitment to reducing its 2010 baseline greenhouse gas (GHG) emissions by 80% by 2030 and a goal of zero GHG emissions by 2040[11] -- and related multi-GW procurement needed for the same;
- Expanded analysis and methodologies to address the Governor's Executive Order 20-04 and the PUC's associated workplan[12];
- Updated analysis on distributed flexibility, which can help support variable renewable resources[13];
- Incorporating its already completed Colstrip Enabling Study which reviewed scenarios for early removal of Colstrip from PGE's portfolio[14] (as noted by Staff);
- Analysis on the impacts of climate change on its loads[15];
- Major regional capacity shortages;
- The inability to develop CTs as avoided resources;
- Lack of Transmission Capacity for avoided resources;
- Among others.

PGE's selective update ignores these other trends that PGE itself says are relevant to its next full IRP. In PGE's stakeholder process, NewSun asked whether PGE's IRP Update would include its newly announced decarbonization commitment. PGE responded that its commitment had only recently been announced, and so there was no possible way it could have known about it with sufficient advance notice in order to incorporate it. This is exactly the concern NewSun has with PGE's update. PGE has complete control over what goes into its IRP Update, either by simply not completing certain analyses in time or making a significant announcement sufficiently in advance to include it, or otherwise simply ignoring some factors that would positively influence avoided costs prices. PGE has no incentive to listen to the feedback provided in its IRP

11 PGE IRP Update at 8, 53, 54.
12 *Id.* at 9, 24.
13 *Id.* at 11, 17, 53.
14 *Id.* at 19, 53.
15 *Id.* at 21.

stakeholder process and update inputs that would increase avoided costs. As such, the Commission should refuse to acknowledge PGE's IRP update until a more complete and more robust analysis can be provided in a full IRP.

2. There is No Pressing Need to Reduce Avoided Costs Now

In addition, there is no pressing need at this time to reduce PGE's avoided cost prices. PGE has not executed any power purchase agreements with new QFs since its post-IRP avoided cost update.[16] This Commission has previously been persuaded to lower PURPA avoided costs when a utility claims that it is overwhelmed with PURPA contracting activity, but that is simply not happening now.

PURPA projects play a key role in advancing Oregon's decarbonization and resiliency goals. The next decade is the most important in-terms of moving the needle on climate change and creating a more resilient electric grid that can better respond to the climate-induced weather extremes Oregon is already starting to see. As such, it would be foolish to further discourage renewable development by acknowledging this IRP Update and allowing PGE to further lower its avoided cost prices.

3. IRP Acknowledgement is Not or Should Not Be Permitted

The Commission's rules provide that a utility "may request acknowledgment of changes, identified in its update, to the IRP action plan."[17] Here PGE has not made any changes to its action plan, therefore, acknowledgment is not an option.

Acknowledgement of an IRP does not guarantee favorable ratemaking treatment, but generally means that "the plan seemed reasonable at the time"; however, in a subsequent rate case, a utility will generally need to explain and justify why it took an action inconsistent with an acknowledged IRP.[18] To mitigate this concern, the PUC will consider a utility's request for acknowledgment of an IRP Update when the utility identifies changes in its action plan, although the PUC "may be unable to acknowledge the plan without the additional information and analysis provided by a new IRP filing."[19]

PGE does not seek Commission acknowledgment of specific avoided cost inputs in its IRP, but rather, it seeks acknowledgement of its action plan. When an action plan is updated in an IRP Update, it generally would mean that the utility has determined that its need identified in an action plan either needs to be moved up or moved out because of changes in circumstances. Therefore, the key purpose of seeking acknowledgement is for the utility to be reassured that its

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16 *See* RE 143. PGE filed 9 PPAs on January 15, 2021 noting in its filing for each that it failed to file the PPAs within 30 days of execution. Three of the PPAs were executed April 15, 2020, five were executed pursuant to a settlement in OPUC docket UM 1829 and the final one is with an existing project.

17 OAR 860-027-0400(8)

18 Order 07-002 at 2, 24 (citing to Order No. 89-507 at 7).

19 *Id.* at 10.

change to its action plan is still reasonable at the time and in order to avoid needing to justify a departure from its prior IRP in a subsequent rate case. If it has not made a change to the action plan it does not need this reassurance.

Rather, when a utility is not updating its action plan, there is even more of an incentive for it to only update items that will lower avoided cost prices, harming its competition, and at the expense of ratepayers. Therefore, the Commission should not acknowledge IRP Updates, when their sole purpose is to lower avoided costs, as in this case.

4. Other Process Suggestions

As an additional matter, NewSun thanks ALJ Sarah Rowe for requiring that PGE make a supplemental filing describing how its IRP Update might impact avoided costs. This helped NewSun review PGE's IRP Update and prepare these comments.

It would be even more informative if PGE also provided a draft of its updated Schedule 201 price schedules and workpapers along with such a filing in the future in order to better understand the combined effects of PGE's updates. Better yet, PGE should provide the same level of transparency in its IRP stakeholder process. Many stakeholders do not have the bandwidth to participate in every facet of the IRP process, but are narrowly concerned with topics affecting PURPA and avoided cost pricing. By providing greater transparency in its IRP stakeholder process about how its proposals will affect avoided cost prices, stakeholders can be more effective participants in that process.

Conclusion

The Commission should not acknowledge this IRP Update because it is a not-so-veiled attempt to cherry-pick inputs to PGE's avoided costs prices that lower the prices, while ignoring other aspects that would have otherwise increased the prices. Further, it simply makes practical sense to await the significant analysis regarding capacity contribution and improvements to the capacity valuation methodology anticipated to come out of the Commissions generic capacity investigation (UM 2011) before allowing PGE to slash the ELCC value of solar by nearly one-third its current value.

Sincerely,

Marie P. Barlow
In-House Counsel
Policy & Regulatory Affairs
mbarlow@newsunenergy.net

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.

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

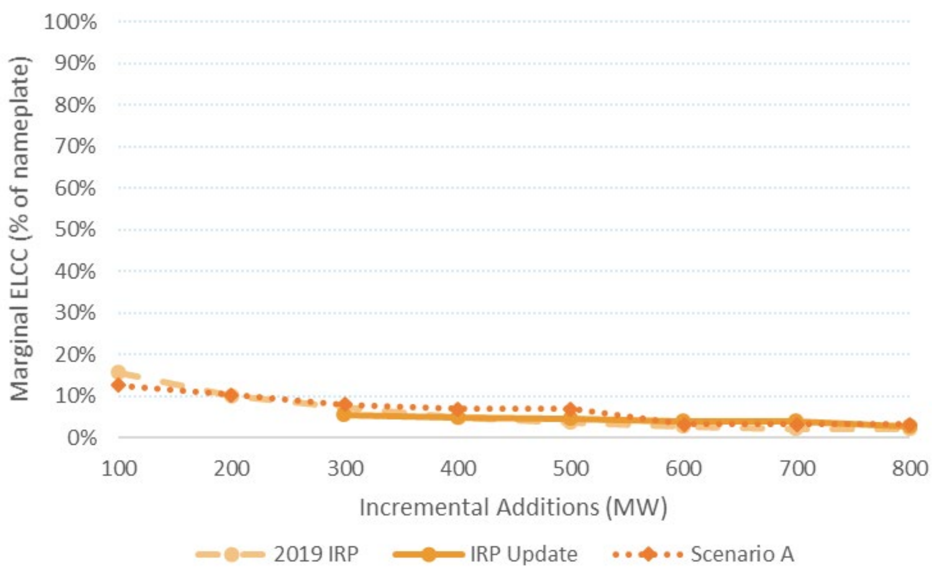
obligations, the improved modeling of dispatchable resources, the statistical consideration of probabilistic weeks instead of independent hourly probability distributions, and the perfect capacity reporting convention). As discussed on page 33 of the IRP Update, the change to reporting in terms of perfect 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.

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

2019 IRP Update
QF Snapshot: executed, standard

Project Name	PPA Execution Date	Resource Type	Nameplate Capacity	Actual COD	Contract COD	Type of PPA	PPA Expiration Date	IRP Update Estimated Start Date	IRP Update Estimated End Date	IRP Update Estimated Annual MWa
Coffin Butte	7/2/12	Biogas	5.66	10/1/12	10/1/12	Standard	9/30/27	10/1/12	9/30/27	5.4
Evergreen BioPower	5/31/17	Biomass	10	2/1/18	1/1/18	Standard	5/31/32	2/1/18	5/31/32	5.2
JC Biomethane	12/9/11	Biogas	1.6	9/26/13	7/31/12	Standard	12/9/31	9/26/13	12/9/31	1.4
OM Power 1	6/21/16	Geothermal	10		6/1/20	Standard	6/21/36	7/1/20	6/21/36	8.3
Falls Creek Hydro	2/19/19	Hydro	4.1		1/1/20	Standard	2/1/34	7/1/20	2/1/34	1.8
Middle Fork Irrigation District Unit 1 and Unit 2	4/2/20	Hydro	2.80	Commercial operati	1/1/22	Standard	12/31/36	1/1/22	12/31/36	2.3
Minikahda Hydropower Co.	2/14/14	Hydro	0.2	2/14/14	2/14/14	Standard	2/20/29	2/14/14	2/20/29	0.03
Tualatin Valley Water District	4/1/13	Hydro	0.11	4/1/13	4/1/13	Standard	3/31/28	4/1/13	3/31/28	0.02
Von Family Limited Partnership	2/14/14	Hydro	0.2	2/14/14	2/14/14	Standard	2/19/29	2/14/14	2/19/29	0.03
Alfalfa Solar	6/26/16	Solar	10		6/26/19	Standard	6/26/35	7/1/20	6/26/35	2.3
Alkali	8/26/16	Solar	10		7/31/19	Standard	7/31/32	7/1/20	7/31/32	2.2
AM - West Silverton	4/19/18	Solar	2.97		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.5
Amity Solar	5/20/16	Solar	4		12/31/19	Standard	5/20/36	7/1/20	5/20/36	0.9
Ashcroft Solar	6/4/18	Solar	2.25		9/30/19	Standard	9/30/39	7/1/20	9/30/39	0.5
Ballston Solar	5/2/16	Solar	2.2	12/18/18	8/31/18	Standard	5/2/36	12/18/18	5/2/36	0.3
Big Horn	9/17/19	Solar	2.2		5/1/20	Standard	8/13/37	7/1/20	8/13/37	0.5
Blue Marmot IX	6/23/20	Solar	10		12/7/22	Standard	6/22/38	12/7/22	6/23/38	2.6
Blue Marmot V	6/23/20	Solar	10		9/27/22	Standard	6/22/38	9/27/22	6/23/38	2.6
Blue Marmot VI	6/23/20	Solar	10		10/13/22	Standard	6/22/38	10/13/22	6/23/38	2.6
Blue Marmot VII	6/23/20	Solar	10		11/2/22	Standard	6/22/38	11/2/22	6/23/38	2.4
Blue Marmot VIII	6/23/20	Solar	10		11/23/22	Standard	6/22/38	11/23/22	6/23/38	2.5
Boring Solar	1/25/16	Solar	2.2	4/3/19	1/31/19	Standard	1/25/36	4/3/19	1/25/36	0.2
Brightwood Solar	3/1/17	Solar	10		11/30/21	Standard	2/1/37	11/30/21	2/1/37	2.1
Bristol Solar	4/19/18	Solar	3		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.5
Brush College Solar	5/25/18	Solar	2		12/1/19	Standard	3/1/38	7/1/20	3/1/38	0.4
Brush Creek Solar	6/23/17	Solar	2.2	5/15/20	4/5/19	Standard	6/23/37	5/15/20	6/23/37	0.3
Butler Solar	1/25/16	Solar	4.0		5/29/20	Standard	1/25/36	7/1/20	1/25/36	0.9
Case Creek Solar	6/22/16	Solar	2.2	10/29/19	5/5/19	Standard	6/20/36	10/29/19	6/20/36	0.3
Connley Solar	5/21/19	Solar	10		12/1/21	Standard	12/1/41	12/1/21	12/1/41	3.1
Coolmine Solar	4/15/20	Solar	1.98		2/2/23	Standard	2/1/43	2/2/23	2/1/43	0.4
Cow Creek Solar	6/4/18	Solar	1.75		2/1/20	Standard	2/1/40	7/1/20	2/1/40	0.4
Day Hill Solar	11/10/16	Solar	2.2		7/14/19	Standard	9/7/36	9/15/20	9/7/36	0.3
DB - Bull Run	4/19/18	Solar	2.565		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.4
DC - Donald	4/19/18	Solar	2.16		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.4
Delaney Solar	12/27/17	Solar	2.5		10/31/20	Standard	12/26/32	10/31/20	12/26/32	0.5
DF - West Eagle Creek	4/19/18	Solar	2.79		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.5
Domaine Drouhin	4/5/13	Solar	0.094	4/5/13	4/5/13	Standard	4/15/28	4/5/13	4/15/28	0.3
Drift Creek	1/25/16	Solar	2.2	5/15/20	4/1/19	Standard	1/25/36	5/15/20	1/25/36	0.4
Dryland Solar	4/19/18	Solar	2.5		12/1/19	Standard	10/31/39	7/1/20	10/31/39	0.5
Dublin Solar	4/15/20	Solar	2.97		2/2/23	Standard	2/1/43	2/2/23	2/1/43	0.5
Duus Solar	5/20/16	Solar	10	2/6/20	12/31/19	Standard	5/20/36	2/6/20	5/20/36	2.2
Eagle Creek Solar	12/27/17	Solar	5		10/31/20	Standard	12/26/32	10/31/20	12/26/32	1.0
Eola Solar	1/29/18	Solar	2.2		1/31/20	Standard	11/30/38	7/1/20	11/30/38	0.4
Fairview Solar	4/19/18	Solar	3		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.5
Firwood Solar	5/20/16	Solar	10	1/27/20	12/31/19	Standard	5/20/36	1/27/20	5/20/36	2.3
Fort Rock Solar I	4/27/16	Solar	10	3/11/20	4/27/19	Standard	4/27/35	3/11/20	4/27/35	2.2
Fort Rock Solar II	4/27/16	Solar	10		4/27/19	Standard	4/27/35	7/1/20	4/27/35	2.2
Fort Rock Solar IV	6/26/16	Solar	10		6/26/19	Standard	6/26/35	7/1/20	6/26/35	2.3
Greenpark Solar	5/8/18	Solar	1.26		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.2
Harney Solar I	6/27/16	Solar	10		6/27/19	Standard	6/27/35	7/1/20	6/27/35	2.2
Hogan Solar	4/27/20	Solar	2.565		2/2/23	Standard	2/1/43	2/2/23	2/1/43	0.4

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	IRP Update Estimated Start Date	IRP Update Estimated End Date	IRP Update Estimated Annual MWa
Kale Patch Solar	5/10/17	Solar	2.2	10/31/19	7/31/19	Standard	5/10/37	10/31/19	5/10/37	0.3
KT - Molalla	4/19/18	Solar	2.97		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.5
Labish Solar	12/1/16	Solar	2.2	12/18/18	8/31/18	Standard	11/10/36	12/18/18	11/10/36	0.3
Lakeview	7/15/15	Solar	10	1/6/20	5/1/18	Standard	7/15/35	1/6/20	7/15/35	2.8
Liberal Solar	12/27/17	Solar	10		10/31/20	Standard	12/26/32	10/31/20	12/26/32	2.0
Milford Solar	4/19/18	Solar	2.97		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.5
Minke Solar	9/17/19	Solar	2.2		5/1/20	Standard	8/13/37	7/1/20	8/13/37	0.4
Mountain Meadow Solar	5/25/18	Solar	2.5		12/1/19	Standard	3/1/38	7/1/20	3/1/38	0.5
NorWest Energy 14	7/28/15	Solar	2.2	2/8/18	12/31/17	Standard	12/31/31	2/8/18	12/31/31	0.3
OE Solar 3	1/25/16	Solar	10	9/7/18	12/30/18	Standard	12/30/33	9/7/18	12/30/33	2.6
O'neil Creek Solar	6/10/16	Solar	2.2	12/9/19	3/24/19	Standard	6/10/36	12/9/19	6/10/36	0.3
Palmer Solar	6/21/16	Solar	2.2		7/1/19	Standard	6/21/36	7/1/20	6/21/36	0.3
Parrott Creek Solar	6/28/18	Solar	2		12/1/19	Standard	11/1/39	7/1/20	11/1/39	0.5
PG - West Sheridan	4/18/18	Solar	3		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.5
Pika Solar	9/17/19	Solar	2.2		5/1/20	Standard	8/6/37	7/1/20	8/6/37	0.4
Radio Solar	11/29/18	Solar	2.5		12/31/20	Standard	12/31/40	12/31/20	12/31/40	0.4
Rafael Solar	6/21/16	Solar	2.2	10/29/19	6/30/19	Standard	6/21/36	10/29/19	6/21/36	0.3
Raven Loop	5/25/18	Solar	2		12/1/19	Standard	3/1/38	7/1/20	3/1/38	0.4
Reed Solar	5/21/19	Solar	2.2		12/1/20	Standard	11/30/40	12/1/20	11/30/40	0.4
Ridgeway Solar	6/4/18	Solar	2.5		12/1/19	Standard	11/1/39	7/1/20	11/1/39	0.6
Riley Solar	6/27/16	Solar	10		6/27/19	Standard	6/27/35	7/1/20	6/27/35	2.3
Rock Creek Solar	2/7/18	Solar	2.2		12/31/20	Standard	2/6/33	12/31/20	2/6/33	0.5
Rock Garden	8/26/16	Solar	10		7/31/19	Standard	7/31/32	7/1/20	7/31/32	2.2
SB - South Wilamina	4/19/18	Solar	2.97		12/2/19	Standard	12/1/34	7/1/20	12/1/34	0.5
Sheep Solar	1/25/16	Solar	2.2	2/8/18	12/31/17	Standard	1/25/36	2/8/18	1/25/36	0.5
Silverton Solar	1/25/16	Solar	2.2	2/8/18	12/31/17	Standard	1/26/36	2/8/18	1/26/36	0.4
South Burns Solar I	7/20/16	Solar	10		7/20/19	Standard	7/20/35	7/1/20	7/20/35	2.2
SP Solar 1	7/28/15	Solar	2.2	2/8/18	12/31/17	Standard	7/28/35	2/8/18	7/28/35	0.4
SP Solar 5	7/28/15	Solar	2.2	2/8/18	12/31/17	Standard	7/28/35	2/8/18	7/28/35	0.3
SP Solar 6	7/28/15	Solar	2.2	8/21/18	12/31/17	Standard	7/28/35	8/21/18	7/28/35	0.4
SP Solar 7	7/28/15	Solar	2.2	6/30/18	12/31/17	Standard	7/28/35	6/30/18	7/28/35	0.4
SP Solar 8	7/28/15	Solar	2.2	2/8/18	12/31/17	Standard	7/28/35	2/8/18	7/28/35	0.4
SSD Clackamas 1	5/8/18	Solar	4		10/5/21	Standard	10/4/36	10/5/21	10/4/36	0.9
SSD Clackamas 4	10/20/17	Solar	2		4/1/20	Standard	3/31/35	7/1/20	3/31/35	0.5
SSD Clackamas 7	5/8/18	Solar	2		4/1/20	Standard	3/31/35	7/1/20	3/31/35	0.5
SSD Marion 1	5/25/18	Solar	2		4/1/20	Standard	3/31/35	7/1/20	3/31/35	0.5
SSD Marion 3	10/20/17	Solar	2		4/1/20	Standard	3/31/35	7/1/20	3/31/35	0.5
SSD Marion 5	5/8/18	Solar	2		4/1/20	Standard	3/31/35	7/1/20	3/31/35	0.5
SSD Marion 6	5/8/18	Solar	2		4/1/20	Standard	3/31/35	7/1/20	3/31/35	0.5
St Louis Solar	6/10/16	Solar	2.2	4/6/20	2/10/19	Standard	6/9/36	4/6/20	6/9/36	0.3
Starbuck Properties	11/2/10	Solar	0.025	1/1/11	1/17/11	Standard	11/2/30	1/1/11	11/2/30	0.003
Stark Solar (Solar Star Oregon)	6/2/17	Solar	10		12/31/19	Standard	12/30/34	7/1/20	12/30/34	2.8
Starlight Solar	5/20/16	Solar	4		12/31/19	Standard	5/20/36	7/1/20	5/20/36	1.0
Starvation Solar	1/25/16	Solar	10	12/27/19	1/25/19	Standard	1/25/35	12/27/19	1/25/35	2.2
Steel Bridge Solar	2/19/14	Solar	2.5	2/18/16	8/19/15	Standard	2/19/34	2/18/16	2/19/34	0.4
Stilorgan Solar	1/17/20	Solar	1.53		11/2/22	Standard	11/1/42	11/2/22	11/1/42	0.3
Stringtown Solar	5/20/16	Solar	4		12/31/19	Standard	5/20/36	7/1/20	5/20/36	1.0
Suntex Solar	5/16/16	Solar	10		7/20/19	Standard	6/1/35	7/1/20	6/1/35	2.2
Thomas Creek Solar	5/31/17	Solar	2.2	11/8/19	2/1/19	Standard	5/31/37	11/8/19	5/31/37	0.3
Tickle Creek Solar	8/23/17	Solar	1.85	12/27/19	1/31/19	Standard	8/22/37	12/27/19	8/22/37	0.2
Townsend Solar	6/4/18	Solar	2.25		9/30/19	Standard	9/30/39	7/1/20	9/30/39	0.5
Volcano Solar	10/18/17	Solar	0.75	7/17/19	3/1/18	Standard	10/18/37	7/17/19	10/18/37	0.1
Waconda Solar	6/4/18	Solar	2.25		2/1/20	Standard	4/1/38	7/1/20	4/1/38	0.5
Walker Creek Solar	2/9/19	Solar	2.5		12/1/20	Standard	11/1/40	12/1/20	11/1/40	0.4
West Hines Solar I	7/20/16	Solar	10		7/20/19	Standard	7/20/35	7/1/20	7/20/35	2.2
Willamina Mill Solar	6/21/16	Solar	2.2		8/14/19	Standard	6/21/36	7/1/20	6/21/36	0.3
PaTu Wind	4/29/10	Wind	9	12/1/10	5/31/11	Standard	5/31/31	12/1/10	5/31/31	3.0