BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 80

In the Matter of PORTLAND GENERAL ELECTRIC, 2023 Integrated Resource Plan and Clean Energy Plan.	ROUND 0 COMMENTS OF RENEWABLE NORTHWEST

I. <u>Introduction</u>

Renewable Northwest ("RNW") is grateful for the opportunity to submit these comments on Portland General Electric's ("PGE") 2023 Integrated Resource Plan ("IRP") and Clean Energy Plan ("CEP"). This is the company's first IRP since House Bill 2021 ("HB 2021") passed in the 2021 Oregon legislative session, and its first ever CEP -- a new planning construct designed to demonstrate a path to achieving zero greenhouse gas emissions by 2040 while ensuring thorough consideration of potential benefits and impacts to Oregon's communities. The IRP and CEP follow closely on the heels of the Oregon Public Utility Commission's ("OPUC" or "Commission") work in docket UM 2225 regarding near-term implementation of HB 2021, and assessment of the plans will run concurrently with docket UM 2273 regarding additional open questions in HB 2021 implementation. As such, review of the plans by interested parties such as RNW, and by the Commission, will be in part a novel enterprise as all parties work to ensure the plans carry out the ambitions established as part of Oregon law by HB 2021.

Because HB 2021 is new, CEPs are new, UM 2225 is fresh, and UM 2273 is in its infancy, RNW expects that this docket will necessarily be something of an iterative process. We appreciate the Commission's establishment of multiple comment opportunities with different timelines. For these Round 0 comments on a relatively short timeline, we plan to raise but not thoroughly address matters that we have identified in our initial review of the plans. But our review is ongoing, so it may well be that we will identify new issues through further review, that issues flagged in these comments will be resolved or clarified by the company in short order, or that questions raised in these comments will be answered in another docket.

To provide a brief walkthrough of the substance of our comments, in our first section we explain how, assessed holistically, PGE's IRP and CEP present a meaningful first step toward the type of wholesale transformation envisioned by those involved in passing HB 2021. We offer appreciation for the company's work to make real progress in updating the planning paradigm to account for the mandates and values enshrined in HB 2021. The next three sections raise issues that, on first read, we believe require additional scrutiny or updating by the company: the plans' greenhouse gas ("GHG") impacts, their approach to PGE's interest in Colstrip Units 3 & 4, and their approach to modeling resources using conditional firm transmission. Our final section addresses a number of additional issues that appear deserving of additional attention by the company and the Commission, again with the caveat that we are still actively reviewing the plans. Finally we conclude by looking ahead to the continued work with PGE and engagement in this docket.

Again, we appreciate the company's work in putting together plans that will make a significant dent in Oregon's GHG emissions and the Commission's consideration of these comments, and we look forward to continued engagement in this exciting docket.

II. Comments

A. PGE's Clean Energy Plan and Integrated Resource Plan Present A Meaningful First Step Toward Achieving Zero Emissions

HB 2021 made it clear that PGE has a legal obligation to "reduce greenhouse gas emissions … [b]y 2030, 80 percent below baseline emissions level[, b]y 2035, 90 percent below baseline emissions level[, and b]y 2040, and for every subsequent year, 100 percent below baseline emissions level."[1] The company's means of achieving this GHG reduction is the CEP.[2] In reviewing a CEP, it is the Commission's mandatory duty to "ensure that an electric company demonstrates continual progress … and is taking actions as soon as practicable that facilitate rapid reduction of greenhouse gas emissions at reasonable costs to retail electricity consumers,"[3] where "continual progress" is defined as "continual progress within the planning period towards meeting the clean energy targets set forth in ORS 469A.410, including demonstrating a projected reduction of annual greenhouse gas emissions."[4]

While some of the details of the company's and the Commission's obligations will be discussed further below, at a high level the IRP and CEP constitute a dramatic departure from "business as usual" integrated resource planning. PGE has centered GHG emission reductions in both its modeling and its narrative. It has done so in a manner that is holistic, considering different scenarios for transportation and building electrification and the interplay between those scenarios and its resource needs. It has assessed and, on first read, appropriately valued Community-Based Renewable Energy ("CBRE") as a significant resource. At the same time, it has identified a significant amount of new renewable generation and storage resources necessary to achieve its 2030 GHG-reduction target (1334 MW wind, 756 MW solar, and 232 MW storage). And it has looked at the technical constraints that may make it challenging to achieve deep GHG reductions, proposing steps now to address potential medium-term barriers that require

[1] HB 2021 (2021), section 3(1), codified as ORS 469A.410(1).
[2] Id., section 4, codified as ORS 469A.415.
[3] Id., section 4(6), codified as ORS 469.415(6).
[4] Id., section 4(4)(e), codified as ORS 469.415(4)(e).

long-lead-time solutions (particularly transmission). In the suggestions and critiques that follow, we encourage the Commission not to lose sight of the transformative nature of these plans. There may be additional work to do, but the plans present a meaningful first step on the path to a clean energy transition for all.

B. Renewable Northwest Recommends Careful Review of PGE's Approach to GHGs

Approximately a year ago, in one of the first opportunities to comment in Commission Docket No. UM 2225, we described HB 2021's approach to GHG emissions -- an approach that establishes binding emission reduction targets but also includes additional discretionary consideration of a CEP's GHG emission impacts[5]:

> HB 2021 is a sweeping piece of legislation that sets forth both broad policy goals and specific requirements that play out at the Commission (among other provisions). While each of the policy statements is important, we wish to highlight one in particular: after HB 2021, "[i]t is the policy of the State of Oregon … [t]hat retail electricity providers rely on nonemitting electricity in accordance with the clean energy targets set forth in section 3 of this 2021 Act **and** eliminate greenhouse gas emissions associated with serving Oregon retail electricity consumers by 2040."[6] Thus the law makes clear that it is providing both a mechanism for achieving 100% clean electricity **and** a broader policy mandate to take whatever steps are necessary to eliminate emissions from Oregon's electricity sector.
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> …
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> The action the Commission must take in response to CEPs is similarly clear in the statute, which also expressly leaves room for Commission discretion in implementation. Most fundamentally, the "Commission shall acknowledge the clean energy plan if the commission finds the plan to be in the public interest **and** consistent with the clean energy targets set forth in section 3 of this 2021 Act."[7] The statute directs the Commission to consider several factors in deciding whether to acknowledge a plan: greenhouse gas emission reductions "and any related environmental or health benefits," "economic and technical feasibility," "reliability and resiliency," federal incentives, customer costs and risks, and "[a]ny other relevant factors as determined by the commission."[8] Again, this section of HB 2021 establishes that the Commission must consider compliance with the law's mandatory greenhouse gas emission-reduction targets **and** the

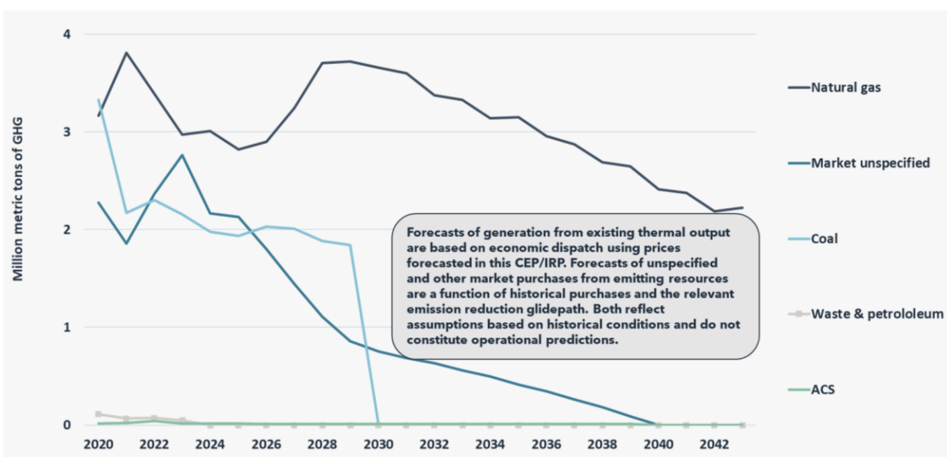
[5] Comments of Renewable Northwest on Planning Framework Straw Proposal, Commission Docket UM 2225 (May 10, 2022), *available at* https://edocs.puc.state.or.us/efdocs/HAC/um2225hac13599.pdf.
[6] HB 2021, Section 2(1) (emphasis added).
[7] HB 2021, Section 5(2).
[8] *Id.*

"reduction of greenhouse gas emissions" as part of its assessment of the public interest -- as well as any other factor the Commission determines is relevant to the public interest.

PGE's CEP appears to achieve HB 2021's mandatory emission-reduction targets based on DEQ's GHG accounting framework; what may merit more attention, however, is the full sweep of emissions impacts associated with the company's plan. Given HB 2021's broad policy language on reducing GHG emissions, the Commission's authority to consider GHG impacts beyond DEQ accounting as part of the criteria for CEP acknowledgement, and the Commission's mandate to "ensure that an electric company … is taking actions as soon as practicable that facilitate rapid reduction of greenhouse gas emissions," close scrutiny and, perhaps, more stringent GHG conditions on CEP acknowledgement may be warranted.[9]

To put a finer point on it, PGE has incorporated HB 2021's mandatory emission-reduction targets into its modeling by first running an economic-dispatch model and then performing an additional layer of analysis that essentially assumes PGE is only using as much of its emitting power as those targets permit, while the rest of that emitting power is sold to other entities.[10] This means that PGE's plan would allow it to generate significant GHG emissions that are not accounted for in the DEQ framework. Perhaps the clearest illustration of this appears in Appendix O of the IRP / CEP, and specifically Figure 177:

Figure 177. Historical and projected total GHG emissions by fuel type



PGE caveats this figure, accurately, noting that the projected emissions "reflect assumptions based on historical conditions and do not constitute operational predictions." For this reason, rather than raising alarm bells or requesting any specific acknowledgement conditions at this early juncture, RNW recommends that PGE provide the Commission, Staff, and other interested

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[9] HB 2021, Sections 2(1), 4(6) & 5(2), codified at ORS 469A.405(1), 469A.415(6) & 469A.420(2).
[10] *See generally* IRP / CEP section 5.3.

parties with additional analysis more thoroughly exploring potential future operating conditions. This analysis could explore sensitivities related to potential WECC buildout and retirement scenarios, emerging market constructs, and the clean-energy policy landscape throughout the WECC, to determine, among other things, whether PGE's thermal fleet would in fact be likely or unlikely to operate under the conditions reflected in PGE's models.[11] Unless additional analysis suggests that PGE's thermal units will likely dispatch significantly less than the IRP / CEP projects in future years, the emissions associated with continued operation of PGE's thermal fleet in the IRP / CEP are concerning.

While the WECC overall may be on a path to a much cleaner, more integrated system of electricity generation, that outcome is not a foregone conclusion, and the current state of play includes significant gaps and seams that could result in significant opportunities for sale of emitting power. As outlined above, the Commission has the authority, and indeed the statutory obligation, to ensure that Oregon's electric utilities are doing as much as possible as quickly as possible (within cost and reliability sideboards) to eliminate GHG emissions. Achieving this policy outcome and carrying out this mandate will likely require additional scrutiny of CEPs' overall emissions impacts.

None of this is to detract from the significant work PGE has done to incorporate Oregon's ambitious GHG emission-reduction mandate into a complex planning exercise on a tight turnaround. Rather, it is to recognize that Oregon's legal regime is intended to align the state's power sector with the realities of climate change. Every avoided ton of GHG emissions matters, and those avoided earlier in time matter more than those avoided later in time.

To that end, one other exercise that may be worth considering is incorporating two additional principles into PGE's GHG glidepath analysis: the social cost of GHG emissions and the time-value of GHG emissions. PGE's glidepath analysis understandably and appropriately appears to focus on direct costs to its customers using the Net Present Value Revenue Requirement metric. This type of analysis is the traditional focus of economic regulation for good reason -- resource decisions have monetary costs that are ultimately borne by customers in rates. But resource decisions also have externalized costs that are equally real and that can be reflected in monetary terms, the most straightforward of which is the social cost of GHG emissions.[12] Running an additional glidepath sensitivity that features the social cost of GHG emissions will likely show additional value in an early, rather than linear, emission-reduction glidepath. This is especially true if that sensitivity features an appropriate discount rate that

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[11] We note that some discussion of these trends appears in the IRP / CEP, e.g. at pp. 35 & 99, but believe there would be significant value in a more thorough analysis of likely future thermal dispatch and resulting emissions.
[12] *See*, *e.g.*, Oregon Department of Energy, "Primer on the Social Cost of Carbon" (May 2020), *available at* https://www.oregon.gov/energy/energy-oregon/Documents/2020-Social-Cost-of-Carbon-Primer.pdf.

accurately reflects the time-value of GHG emissions and GHG emission reductions.[13] It is increasingly well understood that earlier GHG emission reductions are significantly more valuable from a holistic climate perspective than later GHG emission reductions of the same volume.[14] Quantifying this effect in PGE's glidepath analysis will likely suggest that some degree of front-loaded procurement rather than a linear glidepath is the most economic (as well as the most robust) approach to achieving HB 2021's emission-reduction mandates.

C. Renewable Northwest Recommends Careful Review of PGE's Approach to Colstrip

While PGE explores the emissions aspects of continued operation of Colstrip 3 and 4 beyond 2025 in its GHG emissions forecasting, with Colstrip exiting PGE's portfolio by 2030, it is not clear why and how that 2030 exit date was determined. Past analysis had suggested 2025 as an optimal Colstrip exit date on a cost and risk basis. However, it is not clear from the IRP / CEP whether and how cost considerations come into play for continued operation of Colstrip 3 and 4.

If there are other considerations beyond least-cost/least-risk analysis of Colstrip generation, those considerations need further discussion in the IRP/CEP document. For example, RNW acknowledges the potential for complicating dynamics beyond the cost and risk considerations, such as contractual obligations or tangled ownership arrangements. Some details of these circumstances may be confidential, but a high-level discussion or acknowledgement of other factors dictating continued operation of Colstrip is warranted. As it stands, it is not clear why Colstrip 3 and 4 still feature in PGE's portfolio beyond "it will exit in 2029."

RNW suggests further scrutiny of impacts on customers -- through rates and emissions -- be added to the discussion of Colstrip as a generation resource. Any such discussion should also include the potential value of repurposing PGE's rights on the Colstrip Transmission System to deliver non-emitting energy to PGE's system prior to 2030.

D. Renewable Northwest Recommends Changes to PGE's Approach to Modeling Conditional Firm Transmission

Over the past few IRP and RFP cycles, RNW has recommended -- and the Commission has agreed -- that utilities should give adequate consideration to resources using conditional firm transmission. Most recently, in Docket No. UM 2166 regarding PGE's most recent All-Source Request for Proposals, the Commission adopted Staff's recommendation to "[a]ssume that 50

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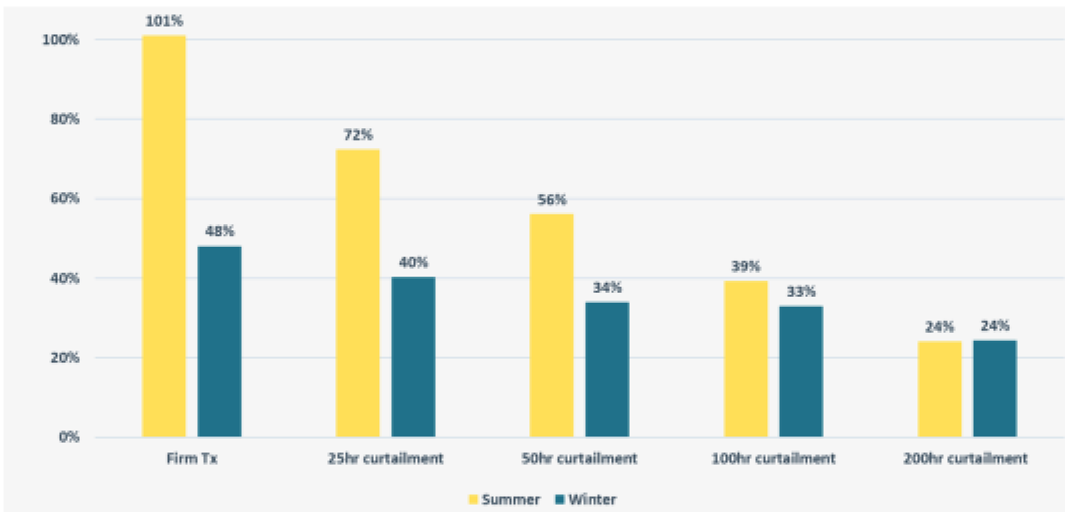
[13] *See*, *e.g.*, Sproul, Barlow & Quinn, "Time Value of Greenhouse Gas Emissions in Life Cycle Assessment and Techno-Economic Analysis," *Env. Sci. & Tech.* (2019), *available at* https://pubs.acs.org/doi/10.1021/acs.est.9b00514.

[14] This makes intuitive sense, especially when considered in tandem with the traditional discount rate PGE did apply in its glidepath analysis, "which weights the impact of near-term costs more heavily than costs accrued later in time." IRP / CEP at 264.

percent of the hours of conditional firm bridge curtailment would coincide with PGE's hours of greatest need instead of all of the hours in its capacity value calculations based on transmission products."[15] In assessing the capacity contributions of resources in its IRP, PGE has followed that practice and assumed that resources using conditional firm transmission will be unavailable for 100 hours (50% of the 200-hour maximum), coinciding with the company's highest need. PGE's Figure 140 shows the effect of this assumption, which reduces the summer ELCC of a proxy hybrid solar resource from 101% to 39%:

Figure 140. Conditional firm sensitivities, McMinnville Hybrid, 300 MW[484]



Over the course of these past regulatory processes, PGE, Commission Staff, RNW, and others have agreed that any answer to the question of how to model conditional firm curtailment is effectively just a guess unless and until there is some effort to quantify likely curtailment for use in modeling. Given the region's increasingly constrained transmission environment, RNW has engaged Grid Strategies as a consultant to assess and quantify this issue.

RNW has attached a memorandum from Grid Strategies explaining their analysis and results as Exhibit A to these comments. The memorandum references a spreadsheet, which is available upon request to max@renewablenw.org, diane@renewablenw.org, or emily@renewablenw.org. RNW has set up a preliminary meeting to walk through the analysis and results with PGE, and we are optimistic that we will be able to agree on a more realistic approach to modeling conditional firm curtailment.

[15] Order No. 21-320 at Appx. A p. 24.

E. Additional Areas Recommended for Further Scrutiny or Detail

1. PGE's Transmission Assumptions Are Likely Discounting the Value of Hybrid Resources and Driving Up Its Capacity Need

Our comments above point to PGE's Figure 140 showing the effect of its transmission assumptions on the effective load carrying capability ("ELCC") of a proxy hybrid solar-plus-storage resource, namely a very steep decline in ELCC for resources using conditional firm transmission. Combined with two other elements of the IRP / CEP, this reduced ELCC value seems to be depressing the selection of hybrid resources in PGE's modeling: first, PGE explains that "[n]o hybrid resources were selected, with the model instead utilizing existing transmission capacity to select stand-alone VER resources with higher capacity factors paired with stand-alone storage options and capacity dense Tx expansion proxies"[16]; and second, PGE explains that "[i]n IRP modeling, resources typically use CF200 transmission after firm transmission is exhausted."[17] Anecdotally, these elements of the IRP / CEP seem to suggest that PGE's model is selecting renewables (which are the most cost-effective resource on a $/MWh basis) that exhaust the available firm transmission, leaving hybrids with depressed ELCC values unlikely to be selected to help address PGE's capacity need.

In their analysis of conditional firm transmission curtailment attached as Exhibit A to these comments, Grid Strategies offer the opinion that:

> Hybrid renewable resources could be particularly valuable to PGE by increasing flexibility to alleviate congestion so renewable resources can be added without curtailment under BPA's Conditional Firm Transmission Service Contracts. PGE should update their modeling to include hybrid resources and account for the value of their flexibility for alleviating congestion as well as using 0 hours of curtailment for the Reference Case when modeling conditional firm transmission service instead of 100 hours of curtailment during peak load.

We look forward to discussing this possibility with PGE's IRP team and are optimistic that a revised approach to modeling conditional firm transmission may result in the selection of hybrid resources to help provide flexibility and capacity to PGE.

2. Offshore Wind Likely Merits Additional Discussion

Overall, PGE's inclusion of offshore wind as a renewable resource fully eligible for selection versus as simply an emerging technology is a productive approach to take considering this

[16] IRP / CEP at 288.
[17] IRP / CEP at 241.

long-lead resource, even though the resource does not appear in the Preferred Portfolio selections up to 2030.[18] The parameters used by PGE are reasonable and rely on the latest research from NREL. We appreciate the approach taken here and acknowledge the use of 960 MW of offshore wind in the Brookings call area as a renewable resource proxy, which we think is reasonable.

Given the location of the resource and the focus overall in the IRP / CEP, discussion of offshore wind as a future resource could benefit from greater granularity and detail around transmission infrastructure required to support this resource. For example, are there necessary transmission upgrades as part of the model parameters? How could PGE bring this resource to load? If offshore wind is a potential least-cost, least-risk option post-2030, given the lead time for developing both the offshore wind resource and the transmission that may be necessary to deliver the resource, we recommend PGE at least offer a narrative around these dynamics and perhaps consider including certain necessary steps in the IRP / CEP action plan.

RNW also suggests including a future resource scenario that considers both OSW and an RTO. Given various dynamics including the richness of the potential OSW resource and the speculated transmission costs we have heard mentioned by BPA and others, we suggest modeling a scenario would likely provide additional value to PGE and the Commission.

3. *PGE's Post-2030 Plan Is Unclear*

RNW appreciates the post-2030 considerations through the IRP/CEP and would like to suggest a more comprehensive, centralized discussion of the various post-2030 elements -- from needs and resources to transmission and emerging technologies. We feel this is particularly important given the important questions on getting to 2040 that could require significant near-term investments or lengthy planning timelines, such as PGE has previewed in its discussions on transmission.

A robust, consolidated post-2030 discussion is especially important given the role of emerging technologies -- many of which are also "long-lead" resources with timelines that exceed the seven year window until 2030 -- both to meet increasing demand and to find resources that complement existing resources. As PGE has flagged in its various discussions of ELCC, post-2030 planning and getting to 2040's 100% emissions-reduction target are not merely a "more of the same" proposition for adding resources. RNW fundamentally agrees with this view and encourages PGE to explore in more detail in the realm of post-2030 requirements and emerging options. We partly encourage this as it sends important signals to those emerging technologies without commiting to procurements. It can also flag potential planning hurdles to adoption, such as transmission upgrade requirements, other infrastructure development, or other organizational recommendations that would implicate long planning timelines.

[18] RNW supports a longer look-ahead period for renewable resources and preferred portfolios given the nature of emerging technologies and long-lead resources. RNW feels that a further "look ahead" would also offer more clarity on future transmission needs.

4. CBIs and CBREs Merit Further Explanation and Development

RNW appreciates the work PGE has conducted thus far on the various Community Benefit Indicators ("CBIs"). We do, however, have some questions and suggestions. For instance, we would like to see more clarity on the choice of a 10% adder for the Resource Community Benefit Indicator ("rCBI"). While we are pleased to see that CBRE projects are prioritized in the modeling, we would like to know more information on the valuation of CBREs. What factors were considered here? Were benefits to *communities* considered in addition to benefits to PGE, and if so, how were they identified and valued?

With Informational Community Benefit Indicators ("iCBIs"), we suggest including more information on how baselines of CBIs will be determined (energy, equity, health and community wellbeing, and economic). Lastly, and pertaining to Environmental Community Benefit Indicators ("eCBIs"), we would like to see additional categories considered. Greenhouse gas reduction is established in this process. Another eCBI category we recommend adding is one (or more) identified and developed with Tribal partners.

RNW appreciates the analysis of CBREs and results showing a low risk and low cost option in constrained transmission environments. We have questions regarding how PGE will bring in community members to co-develop the CBRE-RFP scoring matrix. How can we ensure environmental justice community members' inputs are accurately reflected in this process? To create community-owned projects with community feedback, we believe that many under-resourced communities will need further capacity building and resources to gain experience and ability to engage in planning and building CBRE projects. We also encourage PGE to ensure that EJ community members can understand and participate in the CBRE-RFP by making sure it is written simply and understandably. Lastly, we recommend that PGE develop the entire CBRE-RFP process with community members and not simply the scoring matrix.

5. Community Equity Lens and Engagement Merit Further Explanation and Development

RNW commends PGE on their community engagement throughout the IRP/CEP and their plans for further engagement. In section 14.2, PGE states they are "committed to cultivating and maintaining relationships with new and existing communities and community members, including those who have been historically excluded and underserved." We agree that this outreach and engagement is important. We recommend supplying a plan with more information for how reaching these historically excluded communities will occur. Further information would be useful such as specifics on which communities will be contacted, how they will be engaged with, and when this will occur.

Section 14.2 mentions near term and long term goals and outcomes, but only specifically describes the long term goals and outcomes. We recommend providing more information on the short term goals and outcomes.

We believe the Community Benefits and Impacts Advisory Group ("CBIAG") (described in 14.2.1) will be extremely beneficial to the IRP/CEP process and potentially throughout other avenues as well. We suggest including more information and a timeline describing PGE's plans for the CBIAG and progress to date.

RNW highly encourages PGE to pursue further Tribal outreach and engagement beyond that described in section 14.2.2.

RNW appreciates PGE's dedication to effective community engagement. Section 14.2.9 states that PGE is measuring the effectiveness of this engagement. We suggest, to increase transparency and trust, that PGE show the results of these measurements and if they are not ideal, provide a plan on how to increase the effectiveness of PGE's community engagement.

III. Conclusion

RNW once again appreciates the work that has gone into PGE's IRP and first-ever CEP, and we appreciate this opportunity to offer early comments. We look forward to further engagement with the company and the regulatory process around these plans, and to helping the company and the Commission accomplish their exciting but deeply challenging statutory obligations to eliminate GHG emissions from Oregon's electricity sector.

Respectfully submitted this 2nd day of May, 2023,

/s/ Max Greene
Deputy Director
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Exhibit A

MEMORANDUM

To: Renewable Northwest
From: Grid Strategies, LLC
Date: April 19, 2023
Re: Draft Round Zero Comments for 2023 PGE IRP Presenting Analysis on Conditional Firm Assumptions in the Preferred Portfolio Results

Results

Portland General Electric's (PGE) 2023 Integrated Resource Plan (IRP) conservatively assumes that renewable resources delivered with Bonneville Power Administration's (BPA) Conditional Firm Transmission Service will have their transmission service curtailed during PGE's peak demand periods, significantly reducing the contribution to meeting PGE's peak capacity needs. In particular, PGE's reference case assumes resources delivered via Conditional Firm Transmission Service are curtailed for PGE's highest 100 hours of peak demand.[1]

Our analysis indicates that assumption is unduly conservative, and thus understates the capacity contributions of renewable resources towards meeting PGE's peak demand needs. For the summer and winter peak demand time periods identified by PGE in their 2023 IRP, we show that even with expected growth of renewable resources, in 2030 there would be at most only 37 hours in which actual flows exceed the transfer capacity of the West of Cascade South Path, which is the primary path for delivery of new wind and solar resources to PGE's service territory. 36 of those hours with exceedances occur in the summer and exceed the transfer capacity by an average of 386 MW, while the single winter hour saw a 79 MW exceedance of the available transfer capacity.

These results are a conservative estimate as they do not account for how other resources, including both existing resources like hydropower and resource additions like battery storage, will be dispatched around periods of high renewable output to avoid transmission congestion. Given that all the events in which 2030 estimated transmission flows exceed available transmission capacity last less than 3 hours and are driven by predictable daily solar output patterns, other flexible generators would alleviate that congestion by shifting the timing of their generation in response to market prices. The other generation that flows on the West of Cascade South Path is mostly flexible hydropower, and future additions of battery and hybrid resources near renewable resource areas will contribute further flexibility to absorb generation that would have been curtailed and release it once the path is no longer congested.

Notably, Portland General Electric's (PGE) 2023 Integrated Resource Plan (IRP) Preferred Portfolio does not include any hybrid renewable resource additions.[2] Hybrid renewable resources could be particularly valuable to PGE by increasing flexibility to alleviate congestion so

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[1] PGE, "2023 Clean Energy Plan and Integrated Resource Plan: Appendix J ELCC sensitivities," 545-547, March 2023, https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/db59c8b594a3c380b9d42e90ec9a35aa/2023_PGE_CEP-IRP.pdf.

[2] PGE, "2023 Clean Energy Plan and Integrated Resource Plan: Chapter 11 Portfolio Analysis," 289.

renewable resources can be added without curtailment under BPA's Conditional Firm Transmission Service Contracts. PGE should update their modeling to include hybrid resources and account for the value of their flexibility for alleviating congestion as well as using 0 hours of curtailment for the Reference Case when modeling conditional firm transmission service instead of 100 hours of curtailment during peak load.

Methodology

For their 2023 IRP, PGE identified their peak demand time periods as December and January: hours 7-12 and 17-22, and July and August: hours 17-22.[3] We used the same hours for our analysis.

To start, we pulled data from BPA's website "Rolling 30 Days and Monthly History" for the West of Cascades South Path for July-Aug 2022 and Dec-Jan 2023.[4] We compared actual MW transfers to the MWs of Total Transfer Capacity (TTC) to see how much spare transfer capacity currently exists during the hours of interest.

To create an hourly output profile for renewable generation additions expected to flow on the West of Cascades South Path by 2030, we scaled up a current generation profile using expected wind and solar generation additions for BPA,[5] PacifiCorp,[6] and PGE[7] through 2030. The hourly output profile for future additions of renewable generation that will flow over the West of Cascades South Path was extrapolated from the output profile for current wind and solar power in the region.[8] For the current generation profile, we used EIA 930 data[9] to compile hourly net generation for July-August 2022 and December 2022-January 2023 for wind and solar production in the AVA, AVRN, BPA, IPCO, NWMT, and PACW balancing areas. We compared the 2030 expected renewable wind and solar capacity to the max hourly generation of wind and solar in the summer and winter of our baseline generation profile, which we used as a proxy for current installed wind and solar capacity. Using this ratio of 2030 wind and solar capacity to

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[3] Personal communication between PGE and Sashwat Roy.

[4] Bonneville Power Administration, "Rolling 30 Days and Monthly History," last accessed April 19, 2023, https://transmission.bpa.gov/Business/Operations/Paths/default.aspx.

[5] We assumed no additional wind and solar capacity was added by BPA.

[6] PacifiCorp does not break out wind and solar addition by its East and West service territory. To estimate PacifiCorp West renewable energy additions in 2030 we multiplied PacifiCorp's 2023 IRP Preferred Portfolio 2030 wind and solar additions by the ratio of currently installed wind and solar generation in the PacifiCorp West service area to PacifiCorp's total installed wind and solar generation across both service areas. PacifiCorp, "2023 Integrated Resource Plan Volume II," 2, March 2023, https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2023-irp/2023_IRP_Volume_II_A-P.pdf.

[7] PGE's 2030 wind and solar additions come from the 2023 IRP Preferred Portfolio. PGE, "2023 Clean Energy Plan and Integrated Resource Plan: Chapter 11 Portfolio Analysis," 289.

[8] Our study assumes the West of the Cascades North and South paths will be the limiting factor for new renewables getting to load centers in the Northwest. Slide 13 on Transmission Utilization in the Pacific Northwest from the Northwest Power and Conservation Council notes that the West of Cascades North path is a winter peaking path that primarily serves Northwest Washington. Based on this information, we assumed the West of the Cascades South line is the primary path delivering new renewables to PGE, and assumed all new renewables and demand on the West of Cascades North path will be used by the Puget Sound Area. In addition, Slide 34 from the NPCC presentation indicates that while there may be constraints on the South of Allston path, most of the power on that path is Canadian Hydropower.

[9] U.S. Energy Information Association, "Hourly Electric Grid Monitor," last accessed April 19, 2023, https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48.

current installed capacity, we scaled up the current generation profile and subtracted the baseline profile to create a new 2030 generation profile for wind and solar flowing on the West of Cascades South Path.

For each hour in the peak periods identified by PGE, we added the profile for wind and solar additions by 2030 to existing flows and compared it to the spare transfer capacity of the West of Cascades South Path. We then identified the hours in which the 2030 profile exceeded the spare capacity.

Attached is an excel file showing our analysis in detail.