BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 427

In the matter of Portland General Electric Company, Renewable Resource Automatic Adjustment Clause.	MOTION FOR REVISED PROCEDURAL SCHEDULE OF NEWSUN ENERGY LLC **EXPEDITED CONSIDERATION REQUESTED**

Pursuant to OAR 860-001-0420, and for the reasons set forth below, NewSun Energy LLC ("NewSun") hereby moves the Public Utility Commission of Oregon (the "Commission") for an order modifying the schedule in this proceeding.

The Commission's Order No. 24-091 (the "Order") raises serious questions concerning potentially anti-competitive behavior by Portland General Electric ("PGE") in connection with its selection of the partially utility-owned Clearwater Wind Energy Center ("Clearwater") in its 2021 request for proposals ("RFP"). In the Order, the Commission rejected a proposed stipulation by and between PGE, the Commission Staff, and the Citizen's Utility Board ("CUB") concerning the recovery of costs for Clearwater. In so doing, the Commission expressed the very serious concern that PGE's failure to apply certain RFP requirements to Clearwater—requirements that were applied to all other potential and actual bidders—could compromise the integrity of the RFP process to the detriment of PGE's ratepayers. The Commission further states in the Order that it is not convinced that the terms of the stipulation are in the public interest or that they would go far enough to improve the fairness of future requests for proposals. These issues raised by the Commission in the Order are of utmost importance to PGE's ratepayers, to wholesale power market participants, and to PGE's compliance with its HB 2021 emissions reductions targets. These issues merit a more fulsome investigation and analysis by the Commission than would be afforded by the present schedule.

As it currently exists, the record for this docket is and will remain insufficient to properly address the Commission's concerns. The specific conduct at issue is PGE's disparate treatment of Clearwater, allowing that resource to move forward in the RFP process even though it did not meet the minimum bid requirement that it have 80% long-term transmission. The Commission noted that it appears that this bid requirement was applied by PGE to other potential and actual bidders in a discriminatory manner. If the concerns expressed by the Commission are found to have merit, then this would have far-reaching consequences with respect to billions of dollars of current and future renewable resource procurements. Further still, leaving the issue uninvestigated and unresolved creates doubt about whether PGE's RFPs are worth third-party bidders investing time and energy, or whether they are simply a cover for PGE to procure more benchmark resources or more utility-owned resources.[1]

The record does not contain the following types of evidence that would have a tendency to prove or disprove whether PGE's conduct in the 2021 RFP was prudent, compliant with applicable legal standards, and whether the full recovery of Clearwater costs is in the public interest and results in fair and reasonable rates:

1. Additional projects (and their costs) that could have bid into the 2021 RFP if the minimum bidding criteria required the same amount, 60%, of long-term transmission for all bidders as Clearwater;

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[1] Declaration of Jacob Stephens in Support of Motion for Revised Procedural Schedule.

2. The cost savings ratepayers may have received had existing bids in the 2021 RFP process been permitted to price their bids based on a lower minimum requirement for <u>long-term</u> transmission;

3. The chilling effect that PGE's conduct may have on third-party participation in future PGE resource solicitations;

4. The extent to which PGE's design of the 2021 RFP bidder requirements was orchestrated to eliminate competition and create an unfair advantage for Clearwater;

5. The extent to which the public disclosure of pertinent information concerning Clearwater's failure to meet minimum bid requirements was prevented or delayed;

6. Whether Clearwater failed to meet any other RFP bid requirements;

7. The extent to which PGE's selection of Clearwater is intended or expected to confer a financial benefit to PGE shareholders, at the expense of PGE's ratepayer, over the life of the asset; and

8. The type and level of remedy that is appropriate to deter future similar conduct.

NewSun is cognizant that the near-term implications of this Renewable Resource Automatic Adjustment Clause may result in a very slight credit to ratepayers—a monthly bill decrease of $0.45 for a typical Schedule 7 customer. But an insignificant near-term "credit" should not be grounds to hastily conclude this proceeding without fully exploring and creating a record around the Commission's very real and significant concerns noted in the Order. Having raised these concerns, it is now incumbent upon the Commission to fully investigate, and to issue a reasoned opinion, addressing whether and to what extent anti-competitive conduct occurred, and whether and to what extent PGE's ratepayers may be worse off in the long-term if the outcome of this proceeding does not adequately deter future similar conduct.

While NewSun recognizes that this request is coming at a time after some process has occurred in this docket—Opening Testimony and a Stipulation—the Order raises new and significant issues that have not been fully developed in the record. As it now stands, the schedule would only allow PGE the opportunity to file Reply Testimony and it does not leave sufficient time for even one round of data requests between the date of PGE's Reply Testimony and the date cross-examination exhibits are due. This would create a one-sided record. The Commission should therefore allow Staff, if desired, and intervenors an opportunity to respond to the Commission's requests. Specifically, as NewSun affiliated bids appear to be the second top performing bids in the RFP renewable category, NewSun is uniquely situated to provide the Commission with meaningful testimony about how PGE's conduct has impacted not just the outcome of this particular RFP but has undermined the integrity of the competitive procurement processes going forward.[2] If NewSun affiliates elect not to participate in future solicitations, then PGE's ratepayers would lose the opportunity to benefit from low-risk and low-cost renewable resources that those bids could deliver directly to PGE's system.

For example, lower long-term transmission requirements in the RFP could have allowed additional bidders to participate.[3] Not only that, but it could have also increased the scale of megawatts bid into the RFP, thereby increasing economies of scale and project economics, allowing bidders to submit lower bid prices.[4] Additionally, the cost of

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[2] Declaration of Jacob Stephens in Support of Motion for Revised Procedural Schedule.

[3] *Id*.

[4] *Id*.

long-term transmission is more expensive, so if all bidders were held to the same lower minimum bid requirements, other bids could have been offered at a lower cost.[5] This kind of testimony should be fully developed and part of the record before the Commission in this proceeding.

Given these important considerations, a schedule modification is warranted to provide additional space and process for a full inquiry into the 2021 RFP process and PGE's management of that process. NewSun emphasizes that it does not seek to expand the scope of the issues already identified by the Commission in the Order, or to otherwise unreasonably delay this proceeding. Rather, the issues outlined above, on which the Commission itself has asked for additional clarity, are now within the existing scope of this proceeding given the Commission's rejection of the stipulation in this matter. A reasonable extension is warranted to fully develop the record for this matter.

First, time should be provided in the near-term for at least two rounds of discovery for parties to further investigate the Commission's concerns raised in the Order and then there should be an opportunity for Staff, if desired, and Intervenors to file a round of testimony. The remainder of the proceeding starting with PGE's Reply Testimony could remain as is, but simply be moved out, and expediting the response time for data requests following the submission of PGE's Reply Testimony. As such, NewSun proposes the following schedule:

EVENT	**CURRENT DATE**	**PROPOSED DATE**
Staff and Intervenor Testimony		June 6, 2024
PGE Reply Testimony	April 25, 2024	June 27, 2024

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5 *Id.*

Cross Exam Statements Due	May 9, 2024	July 11, 2024
Hearing	May 16, 2024	~July 18, 2024 (subject to Commission availability)
All Parties Opening Briefs	June 6, 2024	August 8, 2024
Parties Reply Briefs	June 13, 2024	August 15, 2024
PGE Reply Brief	June 20, 2024	August 22, 2024
Target Date for Commission Decision	July 18, 2024	September 19, 2024

Given PGE's impending Reply Testimony deadline of April 25, 2024, NewSun requests expedited consideration of this motion. NewSun conferred with the parties on this motion. PGE and Staff oppose the request. CUB is neutral on NewSun's request but noted a conflict with the hearing date and requested that the parties be permitted to work together to develop a new schedule if NewSun's motion is granted. NewSun does not object to CUB's request but offers the above schedule simply as a proposal and guide for the remainder of the proceeding.

Should this motion be denied, NewSun requests, in the alternative, that at a minimum PGE's data request response time be expedited following the filing of its Reply Testimony, so that parties may properly review PGE's testimony and acquire appropriate documents to be used in cross examination of PGE's witnesses.

Dated this 23rd day of April 2024.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 427

In the matter of Portland General Electric Company, Renewable Resource Automatic Adjustment Clause.	DECLARATION OF JACOB STEPHENS IN SUPPORT OF MOTION FOR REVISED PROCEDURAL SCHEDULE OF NEWSUN ENERGY LLC

I, Jacob Stephens, declare the following:

1. My name is Jacob Stephens, CEO of NewSun Energy LLC.

2. I have nearly 20 years of experience as an executive and entrepreneur in renewable energy, solar, energy storage, and utility-scale power project development, covering a wide variety of energy sources and technologies (thermal, photovoltaic), including leading strategic and on-ground development of projects resulting in over $1B of operational generation and related assets. I have experience in nearly all aspects of the power industry, particularly as relates renewable energy generation development and marketing, including market analysis, site acquisition, development, permitting, financing, engineering, procurement, construction, operation, origination, and transactions across numerous technologies, published research in storage technologies; conceiving, securing, and managing U.S. D.O.E R&D grants; pioneering developments in technologies and markets; and leading, influencing, and engaging in policy developments for local, state, regional, and federal across a variety of regulatory and statutory constructs and venues, including corrective fixed to proposed Oregon statutes, leading new legislation passage in Oregon (radically improving solar permitting), as well as judicial appeals leading to prevailing over state agencies that misinterpreted statutes (ODFW as relates HB 2329, 2019 Session) at the Oregon Court of Appeals, to protect solar permitting in Oregon.

3. I have a Bachelor of Science degree in Mathematics from Virginia Tech, with supporting studies or minors in urban planning, public policy, history, physics, and computer science. My Masters of Business Administration, at University of Arizona's Eller College of Management, concentrated in Entrepreneurship and Finance, and culminated in the launch of my first solar-related start-up, helping pioneer development and finance solutions for large commercial and utility-scale solar in the Arizona market. My activities expanded across and throughout the southwestern U.S. region, helping develop new markets, technologies, and often as a first bidder or project proponent for some utilities' first forays into solar energy, developing commensurate relationships throughout the industry, with

energy executives, financing firms, suppliers, and other market participants. My Campo Verde project near El Centro, CA, became the 9th largest photovoltaic ("PV") project in the world in 2012 when it was commissioned, and was sold to Southern Company at COD, comprising a roughly $600MM project in a year in which the largest American PV manufacturer, First Solar (which built the project), had annual revenues of roughly $1B.

4. I first started doing business in Oregon in 2015, focusing particularly on solar development and related opportunities in the Pacific Northwest, at a time when few in the national solar industry considered Oregon of significance, particularly as relates interconnection through the Bonneville Power Administration ("BPA"), and opportunities to transmit solar through BPA to Oregon and other PNW loads. Over the last 9 years have developed deep knowledge and expertise on the BPA transmission network, and as relates their interconnection and transmission policies, system capacities and constraints, the methodologies for considering and granting interconnection and transmission products, as well as modeling tools, prior studies, and the costs and risks associated with the various products, services, and options.

5. My experience includes participation in over one hundred interconnection study requests—across over a dozen different utilities and transmission providers[1]—and associated studies and scoping meetings, especially as relates BPA and PNW utilities, reading hundreds of related reports, submission of over 400 requests for long-term firm BPA transmission service, comprising collectively tens of thousands of MWs of practical experience, and comprising thousands of hours in the past decade studying, evaluating, understanding, and transacting in the Pacific Northwest, especially as relates BPA service, and especially as relates Oregon and its utilities, Oregon's generation, transmission, and distribution infrastructure, their current capabilities, and expansion pathways and challenges.

6. NewSun projects became the first ever direct-connection BPA solar projects in 2019-2020, as several 10 MW solar Qualifying Facilities ("QFs") began operations, successfully completing and financing over $100MM of operating solar projects, which currently sell and schedule power through BPA to the PGE system, under their respective 2016 vintage standard PPAs for QFs under the Public Utilities Regulated Policy Act of 1978 ("PURPA"). Those projects successfully completed studies with BPA, and commissioned over $10MM of BPA interconnections across three different new BPA taps to its 115-KV system, collectively paying hundreds of thousand of dollars per year in local property taxes in rural Oregon counties. In the process, NewSun has become one of the most experienced companies, if not *the* most experienced and expert company, in

[1] Portland General Electric, BPA, Pacific Power, Tucson Electric Power, Arizona Public Service, Salt River Project, San Diego Gas & Electric, CAISO, SMUD, WAPA, Imperial Irrigation District, Public Service of New Mexico, LADWP, SCPPA, as well as a variety of other consumer-owned power transmission owners, as electric cooperatives, irrigation districts, electric districts, public utility districts, or otherwise, throughout the western interconnect, as well as in other regions of the country, as well as examination of transmission and interconnection options in multiple other countries, including Europe, Africa, and Indonesia.

the permitting, development, financing, interconnection, transmission, and other matters related to solar development in the state of Oregon, especially for BPA connected projects.

7. In the process of these activities, NewSun affiliates have accumulated a multi-hundred MW portfolio of confirmed BPA transmission rights, in addition to an additional GW+ portfolio of transmission positions awaiting confirmation, or completion of upgrades required to grant transmission, comprising a broad diversity of situation, transmission system impacts, and timelines and cost profiles. During the process of securing these positions, NewSun affiliates participated in almost every BPA transmission cluster study since 2016 (all save one), and often out-performed a wide variety of competing IPPs and IOUs in their study results. Most of these transmission requests, including the confirmed transmission, have points of delivery associated with the PGE system.

8. During such time, I was involved in the development and evolution of certain key policies, in particular BPA new variation of Conditional Firm transmission service ("CF") which provided for certain limitations on curtailment exposures for this sub-type of BPA long-term firm ("LTF") transmission service.

9. As such, I am uniquely capable of speaking to, and expert in, BPA related transmission matters and policies, including timelines, processes, viability, and a broad suite of related matters, including how a RFP might consider evaluating bids viability, scoring, pricing, modeling, or other application of transmission and interconnection issues.

10. NewSun affiliate(s) bid three project proposals (with 2 or 3 variations on each) into Portland General Electric Company's ("PGE's") 2021 request for proposal ("RFP"). These bids included solar only, storage only, and/or hybrid solar-plus-storage resources.

11. Many of the NewSun affiliated bids met the minimum bid requirements. Two solar bids amounting to up to 320 MW of solar made the final shortlist.

12. These two NewSun affiliated solar-only bids appear to be the second-most top performing bids in the renewable category.

13. This bid ranking is based on the anonymized/redacted scoring visible in the June 30, 2023 Independent Evaluator's ("IE's") Final Report on Contract Negotiations (which identifies 200 MW and 120 MW solar projects matching the NewSun bids' MWs).

14. Each of these solar bids had viable 2024 energizations, based on a mature, senior, fully-studied BPA high viability interconnection position(s). In other words, bids were for interconnection with complete facilities studies. In these final shortlist cases, all BPA upgrades were "inside the fenceline" at an existing BPA substation.

15. NewSun affiliate(s) had solar and storage options for up to 600 MW with viable 2024 energizations, with commensurate supporting transmission rights (i.e. viable options materially in excess of that which were actually bid into the RFP). Additional highly viable solar and storage could have been bid for 2025 and beyond, in association with various interconnection requests also submitted in 2016 alongside the BPA interconnection requests NewSun successfully energized in 2019 and 2020 for the aforementioned QF PPAs.

16. The number of megawatts NewSun affiliate(s) decided to bid or was willing to submit into PGE's RFP was materially limited due to concerns about counter-party bad faith behavior risks, a concern amplified by the fact that projects bid into the RFP would be subject to exclusivity with PGE for an unknown period of time (that could be extended in PGE's discretion), and risks that would create for development assets, and their commercial risks, combined with concerns and perceptions that PGE would likely not treat third-party bids without utility ownership options fairly. These concerns were bolstered by the nearly unbroken history of PGE dominance of its own RFPs for many years and multiple RFP cycles.

17. NewSun affiliate(s) that bid into the RFP also took into account the exclusivity combined with perceived bad faith counterparty dynamics when pricing their bids and increased the effective bid price as a result.

18. The risks and costs faced by an independent RFP bidder exposed to PGE (or any investor-owned utility ("IOU")) of the Buyer defaulting the Seller (or otherwise failing to provide accommodations for evolving circumstances under a power purchase agreement ("PPA")) can never be the same as a project bid and eventually owned by the IOU-as-RFP-competitor; due to the combination of the lack of contract (PGE does not sign a PPA with itself); ability to provide itself relief or not enforce terms, deadlines, performance, or other obligations or default exposures.

19. PGE nonetheless, as the RFP buyer negotiation with non-PGE-ownership-outcome bids, enjoys tremendous discretion in the negotiations as to when, whether, and/or how much it might allow a bidder counter-party to negotiate relief under these terms and, after PPA execution, situations which may occur. These risks, during bidding, during PPA negotiations, after PPA execution, and after operation, if/when/to the extent such may occur, ultimately affect bidders' view of price, development, and financing risk. Many of these can be fatal, including based on PGE Pro Forma PPA terms, in ways that cannot and are not the same if PGE owns the same asset, or were a counterparty, somehow, in a transaction with itself (i.e. under an affiliate type PPA). Fatal risk exposures, vis-à-vis PPA terms and counterparty behavior risks, have the highest adverse impacts on bidders and bids; they are meanwhile someone non-existent to an IOU bid or resource in the equivalent situation.

20. NewSun affiliate(s)' bids prices would have been lower if long-term firm transmission requirements were lower (proportionally to nameplate MW)—and had thus could have included larger, more economic projects.

21. NewSun affiliate(s) presumed they must follow the RFP rules and could have proposed additional megawatts and options but for the presumption to follow the RFP rules. Bid prices provided presumed having to follow the rules, in particular as to the permissible amount of long-term firm transmission as a %-of-Nameplate for a project.

22. NewSun affiliate(s) were not informed after initial bid submissions, initial short list, final shortlist, or during contract negotiations of the long-term firm transmission requirement being lowered from the 80% or otherwise provided an opportunity to reprice or provide options based on the potential for using less than 80% long-term firm transmission products.

23. NewSun finds it surprising that some RFP bidders were apparently allowed to bid and be evaluated side-by-side with its bids that did not meet these criteria.

24. This revelation, after the RFP was completed, validates NewSun's (and I believe other independent power producers' ("IPPs'")) concerns that the Oregon RFP processes, particularly with PGE, are not fair, transparent, or objective. It will affect future decisions to bid adversely, in the form of pricing and/or limiting participation.

25. NewSun does not believe that any RFP in which PGE is a participant, or has a path to ownership of RFP outcomes, can be fair given the history of PGE RFPs, including those conducted these recent years under OPUC oversight.

26. NewSun believes that other IPPs share similar views as to RFP bias and unfairness in favor of the IOUs, but are scared to express them—or even have organizations of which they are members express them—due to fear of retaliatory behavior from Oregon IOUs, such as blacklisting or abuse of position during the procurement practice.

27. The financial incentives for IOU ownership of RFP outcomes is substantial, well-known, and even commented on by stock analysts, which project IOU-ownership outcomes from RFPs into certain future stock value, including for PGE.

28. NewSun believes these incentives for IOU ownership of generation (and transmission that might be required for IOU-owned generation) create substantial impediments to timely, much less "rapid," or as quickly as possible, reduction of carbon emissions, or otherwise meeting clean energy obligations under Oregon statute. Those effects are amplified by RFP processes (and rate case outcomes) which incentivize and permit (or fail to punish) IOU abuse of position, scoring processes, negotiation dynamics, subjective criteria, contractual relationships with IE, and other factors.

29. It defies logic that large bureaucratic IOUs, which are not specialists in power project development, with higher costs of capital than independently developed and financed projects, would somehow have more competitive power projects in RFP rankings, and continually outperform IPP bidders in RFP after RFP.

30. If the RFP Design had allowed lower long-term transmission requirements (as a percent of project nameplate), this could have allowed not only more viable bidders to participate (both NewSun or otherwise) but could have increased the scale of MW available to the RFP. The economies of scale of larger projects could then also have benefit the bid price(s).

31. If the RFP requirement was for 60% long-term transmission as a percentage of project nameplate rather than 80%, a bidder that had 60 MW of long-term transmission might have bid a 100 MW project instead of a 60 MW (100% LTF) or 75 MW (80% LTF) project. The larger project could reduce the bid price, both in economies of scale, as well as by diluting the fixed interconnection costs.

32. Long-term transmission service on an 8760 or 24/7 basis also costs proportionally more—and is a fixed future operating cost of a bid which must presume a fixed-% amount of long-term firm transmission service. If 40% (rather than 20% or 0%) of project nameplate is permitted to deliver energy using *hourly* firm or non-firm transmission (i.e., other short-term firm or non-firm transmission products offered by BPA), *as and when needed*, the fixed operating transmission costs in the financial models are proportionally reduced by 20 or 40%; and remaining transmission service for facility output could be procured only as-*needed* on a variable basis. This would enable a lower bid price to be considered by bidders, due to both direct and indirect benefits, but especially due to lowering the fixed costs.

33. This effect is amplified and well-illustrated by, for example, a case in which an Oregon solar project might only produce 40-60% of nameplate on even a sunny winter's day, across a few hours, due to shortened daylight hours and the low position of the sun in the sky (with tracking panels pointed up to the sky overhead, not southward, in a typical tracking design); with further variability in output on rainy, cloudy, and snowy days. Such project paying for 100% long-term firm relative to nameplate capacity, would be paying for 40-60% more transmission than it can use, even during the best daylight hours, and paying 100% more than it needs all night long. A project permitted a higher portion of short-term transmission would not bear that full long-term transmission cost as a fixed cost.

34. Project debt sizing and debt service requirements (i.e., debt payment amounts that must be covered by project revenue) also interacts with fixed versus variable costs. Long-term transmission costs would be generally treated as a long-term (year over year) fixed costs, incurred irrespective of actual project output, and affecting debt sizing. Short-term transmission would be modeled as a variable cost (only incurred proportionally with revenue-generating project output).

Lower fixed costs (i.e., debt service and long-term transmission), can enable lower bid prices.

35. A competing project being allowed to proceed with a lower percentage (%) long-term firm transmission relative to project nameplate (MW) would create a competitive advantage for that project in terms of bid price.

36. Price advantages for prospective PPA bids may be further amplified (beyond 1:1 reductions in $/MWH transmission costs) as the frequency of needing transmission for that last 40% may be *more than* proportionally reduced by effects on debt and other financial modeling, including the variable nature of as-needed transmission costs incurred only in proportion to actual project generation (versus costs incurred irrespective of actual generation in a given hour or year).

37. To the extent penalties for under-delivery from any particular project might be not be enforced or imposed (or even exist for IOU-owned vs. IPP-owned projects), this would also create a competitive advantage for such projects. Such could occur due to friendly relationships of an IOU with certain IPPs that provide them other financial benefits, or due to IOU-ownership or affiliation. For IOU-owned generation, there would literally be *no* PPA under which performance obligations or default exposures exist; for IOU-affiliated generation, the IOU would have to, for example, chose to *fine or otherwise penalize itself*, in the event of a shortcoming, which seems incredibly unlikely, at best.

38. NewSun affiliate(s) and other IPP bidders must assume the *full* consequences specified in any executed PPA as the basis of its modeling and default exposures. They may not reasonably presume that PGE will give them relief when such default events may occur. Many of these consequences, absent some relief from the IOU Buyer under a PPA (which relief *cannot* be presumed or relied upon by an IPP bidder or its lenders or tax equity), can be fatal. An IOU-ownership would not reasonably have to assume, if at all, the same fatal risks, consequences, or other costs, as an IPP bidder, as the IOU may assert discretion to grant relief to itself that an IPP may not and should not presume.

39. Any modicum of the probability of such relief for IPP bidders is amplified in the context of an RFP with a history of IOU ownership and/or other concerns of bad faith behavior, which accordingly increases the costs of such risks (or the probability of non-participation).

40. The primary ability to fully mitigate such risks would come through PPA negotiations, to the extent that the IPP bidder succeeds in convincing the IOU counterparty to provide the IPP bidder such contractual relief, which the IOU-as-competitor has a financial incentive to not do, as not providing such relief reduces its own competition and/or increases the pricing of competing bids. As such, the IOU counterparty negotiator cannot be deemed to be neutral.

41. As an example of a fatal PPA risk, if a partly constructed project was not granted schedule relief due to, say, a BPA delay in interconnection, and the PPA specified

that PGE may terminate such PPA in such event, an IPP bidder *must* assume that PGE will terminate the PPA. In that scenario, the bidder and its lenders face total-loss type risks for the facility. The bidder likely also faces foreclosure and/or termination risks under its construction financing, which customarily put the borrower in default if under certain defaults under major agreements, such as the PPA (which would be the primary backstop for the financing of such facility). The same might apply if construction were delayed, weather events, labor shortages, COVID, supply chain issues, or even delay or failure of the Buyer (e.g., PGE) to timely execute or confirm certain documents or actions, such as financing consents and estoppels.

42. These fatal risks for IPP-bidders affect many aspects of their actual bids and consideration of prospective bids, including the ability to bid *at all*, as well as the bid prices. An IPP might have to pay more for accelerated construction to mitigate a construction schedule fatal default risk. The IOU-associated bid might not equally presume the need to incur such costs, due to its comfort in its own ability to grant (or not even need) an extension in project energization schedule. The same applies for other major factors such as minimum power output requirements. In each case, the IPP bidder must up-price (or otherwise risk mitigate, including by not bidding) in order to manage the identical risk.

43. These asymmetric risk dynamics, relative to PPA terms and project ownership, effectively drive up RFP bid prices, and reduce options bid (and thus competition), creat an effect that artificially increase bid prices into Oregon IOU RFP processes. These anti-competitive and unfair dynamics are further exacerbated when bidders with IOU-ownership (or ownership options) are granted further competitive advantages, such as beneficial use of IOU transmission rights or lower %-nameplate long-term transmission requirements.

44. Executives of IOUs must be aware of the financial advantages to the company and its shareholders from IOU-ownership outcomes. It is somewhat impossible to imagine this does not affect internal managerial direction to employees throughout the organization.

45. PGE boasted of its RFP capture rate to shareholders on an earnings call shortly after announcing the Clearwater RFP win and the battery storage build transfer (ownership) outcomes of the RFP.[2]

46. NewSun learned of this indirectly, via press, as PGE had not notified NewSun bidders that the RFP was concluded at such time. PGE did not notify NewSun bidders of the completion of the 2021 RFP before announcing the 2023 PGE RFP.

[2] "In total, we will have secured 786 megawatts of renewable generation and nonemitting capacity resources, with PGE owning 61% of the capacity procured from this highly competitive RFP." Portland General Electric Co (POR) Q1 2023 Earnings Call Transcript, (Apr 28, 2023) https://seekingalpha.com/article/4597906-portland-general-electric-co-por-q1-2023-earnings-call-transcript.

47. Rather, RFP team representatives had indicated, relative to a solar module import tariff (relative to a Department of Commerce investigation) that was believed would be indicated in May of 2023, for which a PPA price adjustor had been proposed in a PPA turn NewSun bidders were willing to execute, that PGE was going to get back to the bidders after the tariffs were announced. It did not, but filed the new RFP, seeking expedited treatment, at the Commission.

48. Upon NewSun inquiry, after attending the first PGE RFP workshop, PGE had a call with NewSun to find out if the 2021 RFP were indeed over, as it had not been so informed by PGE, the I.E., or otherwise. At that meeting, it was indicated that (1) yes, the 2021 RFP was concluded; (2) Jimmy Lindsay, who ran the 2021 RFP process, would be leading the PGE affiliate team. Shiraz Bengali would lead the 2023 RFP team.

49. Mr. Lindsay and Mr. Bengali were the primary negotiating counterparts for the entire 2021 RFP PPA negotiations with NewSun bidders, and presumably for all bidders. Mr. Bengali apparently reported to Mr. Lindsay in the 2021 RFP. Mr. Bengali apparently would then be negotiating in the 2023 RFP with Mr. Lindsay, who would represent the affiliates. Both persons had worked together extensively and were intimately involved, presumably, in nearly all aspects of the 2021 RFP administration and negotiations, including bid scoring, evaluation of minimum bid criteria, initial shortlist recommendations, final shortlisting, and PPA negotiations.

50. Absent direct communication from PGE that the 2021 RFP had been concluded—combined with PGE indication that it would wait to see the Department of Commerce tariff outcomes, so that the parties could continue negotiations based on more concrete tariff information, mitigating the primary outstanding negotiation item in the PPA (price, relative to tariff outcomes)—NewSun bidders were kept in limbo, including as relates both PGE's intentions and the marketability of bids with potential negotiations to continue.

51. PGE actively solicited price increases from competitors during the RFP, including from myself, as relates to NewSun affiliates. This occurred against the backdrop of a variety of post-COVID supply challenges and solar tariff risks (i.e., cost increases and schedule risks) that faced the industry, including PGE's bidders, some of which had become more evident after the RFP bids were received. PGE made clear that this was an issue facing a variety of bidders, as pretext for their allowance of price increases after the Final Shortlist.

52. NewSun was surprised to learn from Staff and IE memos that PGE had solicited price increases from RFP bidders, while then holding constant the bid prices that Clearwater PPA and PGE-owned options, apparently, maintained.

53. The appearance that PGE allowed a benchmark resource with a partial utility-ownership option to move forward when it did not meet minimum bid requirements creates the appearance of (if not outright confirms) the unfairness of PGE RFP processes, as well as the ability of PGE to abuse its position in the RFP

processes to favor outcomes more financially advantageous to itself, both before and after the RFP Design rules are adopted (i.e., in terms of how they propose the rules and PPA terms). This makes me (and others I know) concerned that PGE will engage in similar conduct aimed at favoring utility ownership options in current and future resource solicitations.

54. I am concerned that in current and future resource solicitations, PGE will find ways to use its discretion in the design, evaluation, or negotiation phases of the RFP to give preference to its benchmark or affiliate resources or resources with utility ownership options or otherwise use its position in the process or relationship with the independent evaluator to create an unfair advantage for its benchmark, affiliate, or utility ownership options.

55. PGE's history of picking resources with utility-ownership options in each of its past RFPs for the past 10+ years also gives me concern that PGE has and will continue to find ways to use its discretion and position, before, during, and after the PUC-overseen RFP process, in order to favor utility-ownership options, and to thereby reduce fairness and competition.

56. I believe that PGE's practices with the pro forma PPA terms effectively increases the costs of non-PGE bids by imposing direct or indirect costs and default risks which do not equally apply to PGE's own bids, particularly in cumulative effect. A PGE ownership option does not have a PPA so is not subject to the same terms.

57. PGE inclusion of terms in the pro forma PPA which limit the commercial opportunities for Sellers, such as ROFO rights, obligation to only sell to PGE after a PGE termination of the PPA, and asking Sellers to forswear their rights to sell power under PURPA in the project vicinity if selected, all send negative and anti-competitive messages, impede project financeability, burden bids, and/or otherwise discourage counterparties, inappropriately consume PPA negotiation time (and the starting point of any PPA negotiation), and/or otherwise serve to suppress and impede PGE competition, directly in, as well as outside of, the RFP process.

58. I am also concerned that certain PGE employees working on benchmark bids or providing services to the affiliate may also contribute to creating an unfair advantage for PGE in current and future RFPs, where those PGE employees have worked on past RFPs in the role of reviewing and scoring bids, and where those employees may have past or current access to PGE's models used in the integrated resource plan ("IRP"), and/or been involved in the development of the IRP models.

59. I am concerned that PGE's blackbox scoring model for projects applies curtailment assumptions to certain projects, and/or to certain transmission products, and related energy delivery, and unduly impairs the capacity contribution scoring of certain bids. PGE has made comments throughout current and past RFP processes (including the 2021 RFP) about their treatment of transmission and presumptions of curtailment, particularly conditional firm

transmission (a rarely curtailed product), that make me (given my considerable knowledge and expertise in BPA transmission) believe that their scoring model (which is non-transparent to bidders) presumes degrees of curtailment wholly inconsistent with the nature and history of such BPA products, to the detriment of the capacity contribution, and thus "price scoring" of many bidders.

60. NewSun has seen little, if any, evidence that the IE overseeing the 2021 or (again) the 2023 RFP has any particular expertise in many of the key questions pertaining to bid evaluation and scoring, particularly as relates development viability related minimum bid criteria, and especially as relates BPA transmission and interconnection services, products, processes, financial implications, and viability. This is particularly concerning where PGE is able to influence the IE evaluation of the same matters, including as it scores its competitors, its benchmark bids, and bids which it may believe have a PGE-ownership pathway available to them.

61. Despite these lack of demonstrable qualifications, in the OPUC's recent, January 4th, 2024, 2023 RFP Design decision, and related Commissioner public deliberation, in direct response to issues NewSun raised in written and oral comments, including about the lack of objective RFP scoring criteria (and other statutory standard shortcomings), the same IE (Bates White) that had recently allowed the Clearwater bid to proceed, despite not meeting minimum bid criteria, was pointed to as the fail-safe solution as a supposed remedy to issues NewSun, Northwest Intermountain Power Producers Coalition ("NIPPC"), the Oregon Solar & Storage Industry Association, among others, had raised, expressing concerns about RFP fairness.

62. NewSun repeatedly raised in the 2023 RFP Design matter (UM 2274), in written and oral comments (especially during the January 4th public meeting deliberations) issues with the lack of credibility, expertise, and related demonstrable *inexpertise* and *incorrectness* of PGE's representatives and their assertions about BPA transmission products, particularly as relates conditional firm products, which PGE's representatives continued to inaccurately describe. While the PUC may have *added* eligibility for additional CF products, it still did not address in its order the fundamental issues, and repeatedly raised concerns, about misapplication of curtailment assumption in PGE's black-box model from which 100% of any 2023 RFP bids' scores would be derived. Effectively, PGE *again* conveyed that they would likely mis-model transmission curtailments on some or many bidders, as they could not well, if at all, correctly describe how these transmission products work for BPA, notwithstanding BPA's generally availability (and even "Help Desk") and policies describing these issues.

63. The "price" scoring that a bid is award supposedly comprises a combined score representing value as relates a bids energy costs and contribution to capacity needs of PGE. Any presumed curtailment of bids during peak hours of PGE's needs (whether legitimate, correct, and defensible or not), thus will have a negative impact on a bidder's score, as it will adversely affect their capacity contributions. Material, or entire, curtailment presumed for a bid, during PGE's need hours, will have a material impact on capacity contributions, particularly for

bids supporting PGE's stated capacity needs, which were part of the RFP justification (as blessed, acknowledged, and approved by the PUC in applicable separate RFP and IRP dockets). Thus, misapplication of curtailment assumptions, particularly in a black-box scoring model—one presumably built by PGE's resource modeling team and which some PGE RFP or benchmark staff may have familiarity with—or mistreatment of transmission products, creates serious concerns of abuse, unfair scoring, unfair advantages, and otherwise harmful exposures for the non-PGE-ownership bidders.

64. PGE seems to have won every single RFP it has, or split the win (with a single company, NextEra) as part-PPA, part-Build-Transfer, for over a decade. There appears to NewSun to be little consequence or perceived consequences for such outcomes. Such appears to have resulted in a lack of diversity of ownership outcomes for resources resulting from PGE RFP processes—and all related OPUC oversight of such process.

65. These concerns have a discouraging effect on NewSun's wiliness and extent of participation in any of PGE's RFPs including the current RFP in order to reduce the exposure to unfair treatment, assets being in exclusivity, and effectively increases bid prices.

66. The perception of unfair treatment adversely affects the desire to invest in assets for the benefit of PGE customers notwithstanding existing investments made to date.

67. NewSun believes that the Oregon Public Utility Commission (1) provides undue deference to PGE in RFP proceedings as relates numerous matters, but in particular in RFPs such as the 2021 and 2023 RFP Design decisions as relates transmission products, their eligibility, technical workings, availability, and other aspects; (2) discounts or ignores experts, such as myself, in the same such matters (despite demonstrable and considerable experience); and (3) assigns supposed (but undemonstrated and unlikely) expertise and deference to the IE in RFPs on such critical technical and commercial matters and RFP Design, scoring, and administration, to the detriment of the fairness and integrity of the process, competition, and, ultimately, to the ratepayers.

68. Non-investor owned utility counterparties in the Pacific Northwest are substantially easier to work with, which further discourages my willingness to invest in, transact with, or allowing transmission rights to be used to transact business with PGE. NewSun believes that such discouragement is likely to impede the access of Oregon ratepayers, particularly PGE's customers, from realizing (or even ever seeing) the full suite of options which may be available to serve them, reduce costs, and/or otherwise accomplish critical and statutory objectives, such as the clean energy requirements under HB 2021, the renewable portfolio standard, and other means.

69. These adverse impacts of these RFP dynamics, NewSun believes, are also likely to drive further exposure of ratepayers to market price volatility, higher cost

outcomes from utility-dominated RFP outcomes, and impede reliability of the PGE system, amplifying risks of black-outs, energy and capacity shortages, and ultimately risks to human life for PGE customers.

70. It is my current belief that other independent power producers may have been able to bid into the RFP had the long-term transmission requirements been lowered for all bidders, but that those entities may fear retribution or retaliatory behavior, and so may not come forward to so state.

71. NewSun also fears the consequence of such statements and expression of concerns in such matters with PGE and other investor-owned utilities in both matters related to RFPs and in matters related to the Public Utility Regulatory Policies Act.

72. As such, I believe that action by the Commission in this Clearwater rates matter, as well in each of the other key regulatory processes, sufficient to solve these problems, and deter future IOU abuses and financial incentives to abuse, is necessary to protect competition, reduce ratepayer cost exposures, and protect human life for PGE and other Oregon IOU customers.

73. I believe that this Clearwater rates recovery matter is a critical watershed moment for the Public Utility Commission in terms of the signals it sends to the utility. One of the most critical signals, and questions, will be whether or not PGE and its shareholders make *more* money, or not, as a result of their behavior in, and administration of, this RFP—and thus what they should assume about the likely benefit, or not, of their administration of future RFPs under OPUC oversight. If PGE profitability is superior, as a result of the 2021 RFP outcome, after this matter concludes, I believe it will provide a signal to PGE that such behavior is condoned.

74. I believe that the employment of the IE by the IOU directly creates a financial conflict of interests. Their opportunity for future employment in RFPs is subject to the future nomination by the IOU they supposedly are employed to oversee. One cannot reasonably presume that an IOU which is dissatisfied with the RFP outcomes, as relates its own interests, is as likely to renominate the same IE, particularly as compared to an IE which permits the IOU to advance and procure its own bids, and options which financially favor the IOU running and competing in the same RFP.

75. If behavior and practices continue, I believe that the net effect will also (1) adversely affect Oregon's electric power decarbonization timing, as it will create incentives for the Oregon IOUs to manage RFP procurement in a manner which favors IOU ownership, which inherently cannot be as efficient as a process fully and indiscriminately open to all options, success pathways, ownership outcomes, and solution providers; (2) adversely affect reliability and investment in Oregon; (3) create and amplify financial signals to Oregon's regulated IOUs to structure resource plans and RFPs that favor their own financial returns at the expense of ratepayer costs and reliability, as well as human health and safety, including not

only as relates direct incentive for generation ownership, but also plans leading to higher IOU transmission ownership (and thus rate-based profits) with associated structuralized costs and delays imposed on ratepayers, and to the detriment of competition and diversity and their ability to mitigate and reduce these risks.

76. I do not believe that the consequences in the proposed settlement agreement among Citizens Utility Board, Staff, and PGE were sufficient to deter conduct by PGE to use all tools at its disposal in the RFP, IRP, and other process to favor PGE-ownership outcomes. In particular, consequences purely associated with rare (or seemingly unquantified) transmission curtailment seem unlikely to be material or consequential, given the broad diversity of situations that may apply, as well as access to short-term products, and rarity of such events.

77. If such effect is not material, the deterrence effect of that (or similar) solution(s) would not likely mitigate the issues which the Clearwater RFP outcomes present, nor our concerns about future participation in future PGE or Oregon IOU RFPs, nor the other concerns presented in this declaration.

78. During the development of the 2021 RFP, I provided comments multiple times during the informal and formal parts of the PGE RFP development and approval process that PGE's modeling of Conditional Firm product, based on its own statements that it would presume CF transmission products would be wholly curtailed by BPA during *all* PGE's peak need hours (i.e. LOLP heat map hot spots), in *all* years for a PPA relying on such CF products. This PGE universal worst-case curtailment assumption for such bidders is, and was, grossly inconsistent with the history and future probability of transmission curtailment for BPA CF transmission service, and (as I stated repeatedly at the time) provided an opportunity for material abuse of PGE's position in conducting its RFP, and scoring its bids, including as relates whether its own IOU-ownership track bids may have had full LTF, but competitors would or did have CF LTF. Despite my expertise in these matters, the Commission wholly ignored these concerns, deferring to PGE, and amplifying the abuse potential in this and (as I believe has previously occurred, and will again in the 2023 RFP), based on what happens in their black box model, which is wholly responsible for the so-called "price" scoring (after such or other unknown) curtailment assumptions and/or value magnifiers are non-transparently applied to certain RFP bids. As a result, NewSun's confidence in the fairness of any PGE RFP (including the recently approved 2023 RFP), and the Commission's oversight of these RFP, which appear to lack any objective, transparent, or otherwise demonstrably fair (especially in light of the first two failings) criteria is functionally non-existent.

79. The unfair treatment of NewSun bids, and the Commission's lack of proper oversight to ensure a fair process, has caused financial harm to NewSun affiliates, including the bidders.

80. A lack of consequences, or remedies to such abuses of position by PGE in its procurement processes, undermines faith in the Oregon regulatory process and its markets, as well as the prospects for its investments made, particularly those

supporting potential power service and products, and related development, for the service of or marketing to PGE and its customers, or other customers interconnected to its systems. The concerns then extend beyond just the RFP, but rather to all matters related to PGE, Oregon IOUs, and the matters the Oregon Public Utility Commission regulates and oversees.

81. Dynamics in which Oregon IOU owned resources seem to be the only winners send signals to IPP market participants and developers, such as NewSun, that we should either not market our projects and power to Oregon IOUs, or (as I believe many companies conclude) conclude that the only, or most reliable, path to project success is by selling projects to the Oregon IOUs, so they can own them, as other pathways are unlikely to lead to successes, and IPP-owned outcomes are less viable. This creates a market dynamic of presumption that only IOUs will win in Oregon. This is particularly ironic, and unlikely, but for abuses of competitive and regulatory process, given that only a very small portion of project development in the PNW are associated with PGE. By way of example, of the roughly 200,000 MW of generation development in the BPA interconnection queue, very, very little are PGE owned positions (LSEs requesting interconnection are public identified in most interconnection queues, including BPA's), comprising just hundreds of MW. This is not dissimilar to the prior years in which PGE also dominated its RFP outcomes.

I hereby declare that the above statements are true to the best of my present knowledge and belief and that I understand my testimony will be used as evidence before the Public Utility Commission of Oregon.

Dated this 23rd day of April 2024.

Jacob Stephens