BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 651

In the Matter of Rulemaking Regarding Direct Access Including 2021 HB 2021 Requirements.	**PORTLAND GENERAL ELECTRIC COMMENTS ON STAFF'S STRAW PROPOSAL**

INTRODUCTION

Portland General Electric Company (PGE) submits these comments in AR 651 (rulemaking) in response to the Public Utility Commission of Oregon (Commission or OPUC) Staff's updated straw proposal[1] for policy positions regarding AR 651/UM 2024: Investigation into Long-term Direct Access (LTDA).[2] The scope for the rulemaking was initially explored at a workshop held November 23, 2021, with Staff subsequently circulating a revised scope[3] on December 3, 2021 for discussion at a workshop on December 15, 2021. The updated Staff straw proposal was filed January 12, 2022, followed by a stakeholder response workshop held on January 26, 2022. PGE is grateful to Staff for synthesizing the broad array of stakeholder comments into a single set of proposals.

Staff's straw proposal contained positions on the following topics under the revised scope of AR 651:

- Publicly available pricing.
- Caps and behind the meter (BTM) load growth.
- Non-bypassability.
- Provider of last resort (POLR).
- House Bill (HB) 2021 (2021) Electricity Service Supplier (ESS) Reporting and Disclosure Requirements.

PGE addresses each of these topics in the context of the revised scope and provides its responses below. Staff proposes to bring a recommendation—to open a formal rulemaking—to the June 14, 2022, OPUC Public Meeting.[4] Potentially concurrent with the formal rulemaking, a contested case proceeding will be pursued to address issues that are not appropriate or pertinent to a rulemaking process.[5]

In summary: PGE is supportive of Staff's proposal on publicly available pricing, the solution merely requires the enforcement of existing rules; PGE opposes Staff's proposals that would allow for direct access to grow beyond the existing caps, such a contentious notion is out of scope for this rulemaking and is more appropriately pursued in the contested case portion of UM 2024; PGE recommends that the prevention of BTM direct access load growth is an appropriate issue

[1] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf

[2] LTDA includes PGE Schedules 485, 489, and 490, with transition adjustments contained in PGE Schedule 129.

[3] AR 651, INFORMAL PHASE: Staff's Revised AR 651 Process and Scope, filed December 3, 2021, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah162120.pdf

[4] Id.

[5] UM 2024, Memorandum, filed October 1, 2021, retrieved from https://edocs.puc.state.or.us/efdocs/HAA/ar651haa102538.pdf

for this rulemaking as it relates to the enforcement of existing caps; PGE supports Staff's proposals defining non-bypassability, is open to consideration of a list of non-bypassable conditions in the rules, and agrees that these rules should then by applied during the contested case proceeding; regarding Staff's proposals on POLR, PGE agrees that a resource adequacy program would partially address concerns with emergency default service, but that service still needs to be redesigned in a way that avoids cost shifting and reflects the risk taken on by a POLR; in addition to PGE's concerns regarding the practicality of Staff's proposal for preferential curtailment of direct access customers, it remains unclear how the proposal could benefit direct access customers; and finally, PGE is grateful for Staff's proposals on HB 2021 ESS reporting requirement and seeks to ensure they are in alignment with those for investor-owned utilities.

I. PUBLICLY AVAILABLE PRICING

Staff's Proposal: "To maintain transparency, utilities and ESSs should continue to provide indicative pricing on their websites that gives potential DA [direct access] customers information about transition costs. While potential DA customers may be sophisticated, there still should be a minimum level of transparency."[6]

PGE supports Staff's proposal. Current Oregon Administrative Rules (OAR) require ESSs & investor-owned utilities (IOUs) to provide the Commission with a URL address for a website where they regularly post their indicative pricing.[7] This rule simply needs to be enforced, since ESS rates are not transparent, and this rule is intended to ensure that ESS prices too, are subject to a minimum level of transparency. A link to PGE's full tariff, including its LTDA transition adjustment (Schedule 129) can be found on the PUC's website.[8]

II. CAPS AND BEHIND THE METER LOAD GROWTH

Staff's Proposal: "The Commission will set DA caps, if implemented, in the UM 2024 or other contested case process. The October 1, 2021, Memorandum requires discussion of firmness of caps. To the extent that caps are implemented in a future contested case, Staff proposes that overall direct access caps will be recalculated each year prior to the annual election window in

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[6] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf p2

[7] See*:* OAR 860-038-0275(1) and OAR 860-038-0275(4).

[8] OPUC, Rates and Tariffs, Tariffs – Electric and Natural Gas, Electric – Portland General Electric, retrieved from https://www.oregon.gov/puc/utilities/Pages/Rates-Tariffs.aspx

order to determine availability under the cap. Caps would be updated to be responsive to the ongoing risks of the program."[9]

PGE opposes including in the rulemaking the issue that "Caps would be updated to be responsive to ongoing risks of the program".[10] In PGE's view, developing a mechanism to change the level of DA caps is an issue that should be best addressed in the contested phase of an investigation to provide for the appropriate forum for parties to present their positions and respective evidence, ensure the development of a full evidentiary record, and for the Commission to make a decision based on this robust record. Changing the level of the DA caps strongly affects the structure of the competitive retail electric market in Oregon, as well as influences any resulting cost shifts.

Caps are a necessary form of customer protection that, as the Commission has stated, "place bounds on potential negative outcomes, particularly where future system impacts for a course of action are unknown or unknowable."[11] Caps further stabilize retail electric markets, providing market participants the ability to appropriately plan for customer load. Absent firm caps, PGE's customers are potentially subject to massive swings in the market and planning for load, which creates the potential for unwarranted and significant cost shifts. PGE's position is that any potential cap expansion mechanisms should be contemplated only after the Commission's Investigation into Resource Adequacy in the State (UM 2143) has been resolved, and they are considered alongside issues such as "Evidence of cost-shifting" in the UM 2024 contested phase.[12] Costs associated with resource adequacy are core to evaluating the magnitude of cost shifting between cost-of-service (COS) and direct access customers. While changes to DA caps are an issue for consideration in the contested phase of UM 2024 due to the significance of new issues raised, the issue of existing caps being held firm (against pressures such as BTM DA load growth) *is* within the scope of this rulemaking (see Staff's proposal on BTM load growth below).[13]

Staff's Proposal: "Petitions to exceed the capacity cap will be examined through a 90-day process similar to what has been outlined for VRET programs in UM 1953."[14]

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[9] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf p2

[10] AR 651, INFORMAL PHASE: Staff's Revised AR 651 Process and Scope, filed December 3, 2021, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah162120.pdf p2

[11] UE 335, Order No. 19-128, issued October 26, 2018, retrieved from: https://apps.puc.state.or.us/orders/2019ords/19-128.pdf

[12] UM 2024, Memorandum, filed October 1, 2021, retrieved from https://edocs.puc.state.or.us/efdocs/HAA/ar651haa102538.pdf p3

[13] Id.

[14] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf

PGE is opposed to this proposal for two reasons: i) this suggestion is out of scope of the rulemaking, and ii) it is a mechanism used in a COS tariff and not directly applicable to DA.

As with Staff's previous proposal to update caps in response to ongoing program risks, PGE suggests that it would be premature and outside the scope of this rulemaking to consider petitions to exceed the cap. To the extent that any mechanism to expand the cap by petition is considered by the Commission, such consideration would, in PGE's view, be better explored as part of the UM 2024 contested proceeding into issues such as the "Level of and applicability of caps on program size."[15]

Staff Proposal: "Regarding BTM load growth, Staff views this issue as tethered to the existence and size of DA caps overall. Staff is amenable to accommodating BTM load growth assuming all risks, including cost-shifting concerns, are otherwise addressed through transition charges, Resource Adequacy, etc."[16]

While PGE share's Staff's view that BTM load growth is tethered to the existence and size of DA caps overall, PGE believes that a finding on "firmness of caps" is ripe for this rulemaking, but does not believe addressing growth *beyond* the caps is appropriate for this rulemaking for the reasons previously discussed. PGE's LTDA program has a cap of 300 MWa and our New-Load Direct Access (NLDA) program has a 119 MWa cap.[17] These caps are an essential tool to help mitigate the potential for cost shifting as they place limits on "unknown and unknowable" system impacts and on the amount of load that can return to PGE on short notice that PGE is then required to serve with emergency default service (see POLR discussion).[18] In PGE's LTDA Design Straw Proposal we advocated for hard constraints on load growth BTM if/when PGE's LTDA program reaches 300 MWa and/or our NLDA program reaches 119 MWa, suggesting that any further load growth beyond the cap be placed on COS.[19] This remains PGE's proposal. For purposes of this rulemaking, the "firmness of caps" was the explicit issue scoped in the October 2021 memorandum.[20] To the extent Staff's proposal is suggesting that BTM load growth could exceed the firm caps established to ensure customer protection, then we have a different issue. This issue would be directly tied to the cap expansion rather than ensuring the firmness of existing caps.

[15] UM 2024, Memorandum, filed October 1, 2021, retrieved from https://edocs.puc.state.or.us/efdocs/HAA/ar651haa102538.pdf p3
[16] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf p2
[17] NLDA offered through PGE Schedule 689, with transition adjustments contained in PGE Schedule 139.
[18] UE 335, Order No. 19-128, issued October 26, 2018, retrieved from: https://apps.puc.state.or.us/orders/2019ords/19-128.pdf
[19] UM 2024, PGE Straw-Proposal for Changes to Long-term Direct Access Programs, filed August 23, 2021, retrieved from https://edocs.puc.state.or.us/efdocs/HAC/um2024hac82045.pdf p12
[20] UM 2024, Memorandum, filed October 1, 2021, retrieved from https://edocs.puc.state.or.us/efdocs/HAA/ar651haa102538.pdf p3

Consideration of such a departure from established Commission policy should only be considered in the context of the future UM 2024 contested proceeding, not part of the rulemaking proceeding.

In addition, Staff's proposal would allow BTM load growth "assuming all risks, including cost-shifting concerns, are otherwise addressed through transition charges, Resource Adequacy, etc."[21] Risks, including cost-shifting and transition charges, are expected to be addressed in the UM 2024 contested case proceeding, [22] while resource adequacy is still under investigation in UM 2143.[23] Thus, any allowance for BTM load growth to exceed the caps should not be considered separately from the resolution of those risks in the other dockets, and is therefore not appropriate for the rulemaking docket.

III. NON-BYPASSABILITY

Staff's Proposal: "Non-bypassable charges are those charges that may not be avoided by the transition to direct access."[24]

Staff's Proposals: "Staff proposes to define non-bypassable charges as costs that the legislature directs to be recovered by all customers as well as costs determined by the Commission to be associated with implementing public policy goals related to reliability, equity, decarbonization, resiliency, or other public interests."[25]

PGE supports these two proposals and appreciates Staff's efforts to define non-bypassability at this stage and within the context of the rulemaking. PGE has emphasized on other occasions that mandated costs associated with effectuating policies that are in the public interest should not be allowed to be bypassed by choosing an alternative energy supplier.[26] Furthermore, the Commission is statutorily required to prevent "unwarranted shifting of costs" from direct access customers to other retail electricity customers.[27] "Non-bypassability" is shorthand for the principle that the costs of policies for which there is a societal benefit should be borne equally by

[21] AR 651, INFORMAL PHASE: Staff's Revised AR 651 Process and Scope, filed December 3, 2021, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah162120.pdf p2
[22] UM 2024, Memorandum, filed October 1, 2021, retrieved from https://edocs.puc.state.or.us/efdocs/HAA/ar651haa102538.pdf p3
[23] UM 2143, Investigation into Resource Adequacy in the State, retrieved from https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22698
[24] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf
[25] Id. at 2
[26] UM 2024, PGE's Opening Comments at 26-29, filed March 16, 2020, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=um2024hac154125.pdf&DocketID=21962&numSequence=52; PGE Advice No. 20-09, filed April 23, 2020, retrieved from: https://edocs.puc.state.or.us/efdocs/UAA/adv1112uaa165524.pdf ; and UE 392, PGE's Direct Testimony of Maria Pope and Brett Sims at 15, filed July 9, 2021, retrieved from: https://edocs.puc.state.or.us/efdocs/HTB/ue394htb155528.pdf .
[27] ORS 757.607(1).

all retail electricity consumers, regardless of whether they are served by an IOU or an ESS.[28] Similarly, investments made in specified resources to achieve policy goals legislated by the State, including load-stabilizing and system reliability efforts that will provide future benefits and/or cost avoidance to all users of PGE's distribution system regardless of energy supplier, should be recovered from all who benefit from such resources.

HB 2021 provides legislative guidance on evaluating "public interest", stating that "In evaluating whether a plan is in the public interest, the commission shall consider […] any related environmental or health benefits" and "Any other relevant factors determined by the Commission."[29] Staff's proposal also includes policy goals related to "equity" that are, in PGE's view, consistent with the legislature's direction in HB 2021, to be implemented "in a manner that minimizes burdens for environmental justice communities".[30]

Staff's Proposal: "Staff is open to including a list of conditions in the rule that make costs associated with a policy non-bypassable. For example, above-market costs associated with implementing public policy goals."[31]

PGE supports this proposal with some caveats. Staff includes "above-market costs" as an important example, but it should be noted that the costs associated with implementing public policy goals such as income-qualified bill assistance do not have above market costs.[32] As discussed in relation to the previous Staff proposal, non-bypassability requires the consideration of additional issues beyond above market costs, including community-sited energy, resiliency, environmental and health benefits, and minimizing impacts on environmental justice communities.

[28] See, for example: An Act Relating to Clean Energy, House Bill 2021 §14(2) 81st Oregon Legislative Assembly (2021); An Act Relating to Public Utilities, HB 2475 §(7)(2), 81st Oregon Legislative Assembly (2021); An Act Relating to Alternative Fuel Transportation, HB 2165 §(2), 81st Oregon Legislative Assembly (2021). Available at https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

[29] An Act Relating to Clean Energy, HB 2021 Section (5)(2)(a-f), 81st Oregon Legislative Assembly, 2021 Regular Session. Available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

[30] Id. at Section (2)(4). Note HB 2021 Section (1)(5) defines "Environmental Justice Communities" to include "communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including seniors, youth and persons with disabilities."

[31] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf

[32] See An Act Relating to Public Utilities – Authorizes PUC to consider differential energy burden and other inequities of affordability in rates, HB 2475, 81st Oregon Legislative Assembly, 2021 Regular Session. Available at https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2475/Enrolled

Staff's Proposal: "In the contested case phase of UM 2024, the current list of non-bypassable charges will be determined, which will include consideration for types of charges associated with HB 2021 that cannot be avoided under HB 2021 Section 14."[33]

PGE is supportive of establishing, in rules, a definition of non-bypassability and a method of determining the types of costs to be characterized as non-bypassable, then waiting until the UM 2024 contested proceeding to apply that definition and method.

Staffs' Proposal: "Non-bypassable charges should be allocated to a DA customer in the same method as a COS customer of similar size and load profile."[34]

PGE interprets this proposal as standing for the proposition that, at least with regard to non-bypassable charges, DA customers should be treated in a consistent manner, meaning they should be charged the same amount of non-bypassable charges as those COS customers in the same class. If PGE's interpretation is correct, then PGE supports this proposal. If, however, PGE has misinterpreted the intent of Staff's proposal, then PGE reserves the right to alter its position on this particular proposal once our understanding of Staff's intent is corrected.

IV. PROVIDER OF LAST RESORT

Staff: "ESS participation in an RA [resource adequacy] program and also charging DA customers for POLR backstop capacity is duplicative. Based on the current NWPP program and anticipated state RA requirements, customer choice for RA/POLR options is not feasible or warranted. IOUs continue to have POLR obligations and should seek to implement rates that are reflective of the cost of providing such service. A separate capacity charge for POLR obligations is not necessary because RA planning ensures adequate planning capacity."[35]

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[33] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf p 2
Note: HB 2021 Section 14 states:
"The commission shall review and identify costs incurred by electric companies for obligations not similarly imposed on electricity service suppliers to comply with sections 1 to 15 of this 2021 Act that retail electric consumers served by electricity service suppliers may avoid by obtaining electric power through direct access and ensure that the identified costs are recovered from all retail electricity consumers, are calculated and recovered on the basis of electricity consumption and bear a direct relationship to costs borne by retail electricity consumers served by electric companies." Available at https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2475/Enrolled

[34] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf p3

[35] Id.

Staff's Proposal: "The assumption for ratemaking purposes is that an ESS demonstrating RA is sufficient to ensure capacity for a direct access customer in an emergency situation."[36]

Staff's Proposal: "Emergency default service rates shall be designed to mitigate or avoid cost-shifting."[37]

PGE is the sole POLR for all of our customers (both COS and DA) and would remain so in the presence of a functioning resource adequacy program. When an ESS fails to provide power to a DA customer, PGE steps in as POLR through our emergency default service. Resolving resource adequacy planning concerns would not necessarily address all cost-shifting concerns related to capacity and POLR. PGE therefore welcomes Staff's proposal to redesign emergency default service to avoid cost-shifting to COS customers. PGE sees Staff's proposals related to "ESS participation in an RA program", "ESS demonstrating RA", and "Emergency default service rates" as related. Given that, PGE will consider them together.

In response to HB 3633 (2001) PGE designed Schedule 82[38]to "provide back-up service for any direct-access customer that loses its ESS and has not provided PGE with the notice required to receive service under the applicable standard offer service rate."[39] PGE proposed to provide this back-up service on an "as available" basis to "prevent a returning direct access customer from causing PGE to curtail service to other customers who did not go to direct access […] other customers should not be required to suffer rolling outages to provide emergency default service or pay for standby resources for direct access customers." Staff noted that "[b]ecause PGE remains the [de facto] *provider of last resort* within its service territory […] the company is obligated to provide safe and adequate service to all customers within its service area" [emphasis added]. The Commission resolved that "customers who choose direct access should not be limited to default service on an "as available" basis."[40] PGE therefore recommends that the rules clearly state that PGE is the POLR for all retail customers in their service territory.

Per PGE's Schedule 81 (Nonresidential Emergency Default Service), a direct access customer no longer receiving service from its ESS and returning to PGE without the required notice is charged 125% of ICE-Mid-Columbia (Mid-C) Firm Index plus 0.306 cents per kWh for wheeling, plus line losses. After five business days (or before) the customer is moved to PGE's standard offering (daily market pricing) and has the option of seeking a new ESS. Updating emergency default service to accurately reflect the costs of providing such a service (even with an ESS planning to be resource adequate) would ensure direct access customers are accurately paying for the costs of returning to PGE without the required notice and without shifting risk to or subsidization from

[36] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf p3
[37] Id.
[38] Nonresidential Emergency Default Service is now provided through Schedule 81.
[39] UM 115, Order No. 01-777 at 38, issued August 31, 2001, available at: https://apps.puc.state.or.us/orders/2001ords/01-777.pdf .
[40] Id.

COS customers. To the extent that RA issues are resolved to the Commission's satisfaction, that would go some way to resolving PGE's concerns that ESSs were planning for qualifying capacity to meet their forecasted load, given that IPR Guideline 9 prohibits PGE from planning for such capacity while we are also POLR.[41] However, resolving resource adequacy planning concerns would not necessarily address all cost-shifting concerns regarding capacity and emergency default service. PGE therefore welcomes Staff's proposal that emergency default service "shall be designed to mitigate or avoid cost-shifting". [42]

Staff's Proposal: "Utilities may choose to preferentially curtail customers on emergency default service, but only if all other options have been pursued; including RA resources set forth for customer's load, other ESS or market options, any capacity sharing agreements, and generation from the utility's resource stack."[43]

PGE has concerns about this proposal given its potential impracticality and the fact that it is a solution to a problem that is being resolved in UM 2143 and through the NWPP WRAP. In addition, beyond the benefits of delaying or postponing the curtailment of COS customers, it is unclear what costs could be avoided by preferentially curtailing direct access customers on emergency default service during an energy emergency.

For further insight as to why preferential curtailment of customers on emergency default service is, in PGE's view, impractical, PGE offers the following information: On PGE's system there are nearly four hundred existing NLDA and LTDA service points, most of which are unique and would require specific equipment, communications, and control re-configuration to allow for the preferential shedding of their respective loads. Under PGE's current rules, in a load shedding (curtailment) event, PGE sheds load at the feeder breaker level; we are unable to discriminate between specific customers or customer types on the same feeder. Since most of the LTDA service points are on general purpose feeders that also serve COS customers, PGE would need to install additional equipment to enable load shedding on an individual LTDA/NLDA customer basis. For example, the estimated costs for a single primary metered customer served by *overhead* service would be approximately $70,000 which is expected to would cover the purchase and installation of a recloser to effectuate discriminatory load shedding of that single service point. It would be much more expensive if we were to install the needed equipment at service points served by *underground* equipment, which coincidentally encompasses most of PGE's LTDA customer's service points. For underground service, each service point configuration would need to be reviewed to determine the reconfiguration and equipment that would allow for curtailment of their load. If such an approach is to be pursued, it needs to be determined what entity will pay for the

[41] IRP Guideline 9 states: "[a]n electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier." Public Utility Commission of Oregon. "Order 07-002." UM 1056. Public Utility Commission of Oregon. 8 Jan 2007, page 19. https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

[42] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf p3

[43] Id.

significant incremental costs to operationalize such preferential curtailment of LTDA and NLDA customers on emergency default service in an energy emergency.

The possible exception to the above could be future NLDA customers proposing new construction, given that the distribution planning for their load may not yet have occurred so the ability to plan for the curtailment of their specific load could be anticipated, during the distribution design-work phase. PGE explored this in Advice No. 1105/20-06, where we prosed preferential curtailment of NLDA customers during an emergency in the absence of an RA solution.[44] In the Public Meeting on April 21, 2020 the Commission rejected and denied PGE's NLDA curtailment proposal.[45] Staff's proposal modifies PGE NLDA curtailment proposal in two ways: i) Staff extends the preferential curtailment to both LTDA and NLDA customers; and ii) Staff introduces the failure of an ESS (given the DA customer is on emergency default service) as a prerequisite for preferential curtailment. Even so, there has been significant progress at both the state (UM 2143) and the regional level (NWPP WRAP) in ensuring all load responsible entities (IOUs and ESSs) are beginning to transparently plan for resource adequacy in the same way.

V. HB 2021 ESS Reporting and Disclosure Requirements

PGE appreciates the work of Staff in assembling proposals around HB 2021 reporting and disclosure requirements for ESSs. The Company will limit these comments to an overall recommendation and a specific observation, rather than go through each of Staff's proposals. Overall, it is essential that the HB 2021 reporting and disclosure requirements for ESSs under discussion in AR 651 are in alignment with the reporting and disclosure requirements for IOUs being explored in UM 2225 (Staff HB 2021 Investigation into Clean Energy Plans).[46]

Specifically, Staff propose that ESSs "will begin reporting in 2027 (3 years prior to the first compliance target date".[47] As discussed at the AR 651 Workshop held January 26, 2022, PGE observes that a 2027 start date for ESS reporting is unlikely to lead to "Actions to make continual

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[44] Advice No. 1105/20-06, PGE Revisions to Rule C on Emergency Curtailment & Updating the Short-Term Emergency Curtailment Plan, filed March 20, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/UAA/uaa104539.pdf
[45] Advice No. 1105/20-06, PGE's Second Supplemental Filing of Advice No. 20-06, Revisions to Rule C on Emergency Curtailment & Updating the Short-Term Emergency Curtailment Plan, filed April 24, 2020, retrieved from https://edocs.puc.state.or.us/efdocs/UAC/adv1105uac16521.pdf
[46] UM 2225, Staff HB 2021 Investigation into Clean Energy Plans, retrieved from https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23160
[47] AR 651, INFORMAL PHASE: Staff's Announcement for the January 26, 2022, Workshop, filed January 12, 2022, retrieved from https://edocs.puc.state.or.us/efdocs/HAH/ar651hah152631.pdf p3

progress toward meeting the clean energy targets".[48] PGE recommends that the proposed rules embed the intent in HB 2021 that for purposes of compliance with the greenhouse reduction goals, IOUs and ESSs be treated comparably. This intent can be understood through the language of the bill itself, for example: the use of "retail electricity provider" rather than separate use of electric company and electricity service supplier; the requirement that the Commission provide a reliability pause to ESSs that is "comparable" to that provided to IOUs; and a "comparable" cost cap exemption.[49] Therefore, PGE would like to see reporting by ESSs that compares in timing to that of Clean Energy Plans filed by IOUs.

CONCLUSION

PGE looks forward to Staff circulating draft rule language based on the positions refined through straw proposals, workshops, and comments received by March 23, 2022, followed by workshops on April 11 and May 12 before Staff makes a recommendation to open a formal rulemaking at the Commission Public Meeting on June 14.

Respectfully submitted this 14th day of February 2022.

/s/ *Nidhi J. Thakar*

Director, Resource and Regulatory Strategy and Engagement

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[48] An Act Relating to Clean Energy, HB 2021 Section (3)(c)(A), 81st Oregon Legislative Assembly, 2021 Regular Session. Available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

[49] Id. at Section (2)(1) and Section (9)(9) respectively.