**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UM 2273**

In the Matter of )
)
PUBLIC UTILITY COMMISSION OF )
OREGON, )
)
Investigation Into House Bill 2021 )
Implementation Issues. )
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OPENING BRIEF

OF THE

OREGON CITIZENS' UTILITY BOARD

July 25, 2023

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## I. INTRODUCTION

Pursuant to Administrative Law Judge Mellgren's July 24, 2023, Ruling, the Oregon Citizens' Utility Board (CUB) submits its Opening Brief in the above-captioned proceeding. The Oregon Public Utility Commission (PUC or Commission) has been engaging with the public and interested parties on guidance and expectations for implementation of HB 2021, Oregon's 100% Clean Energy law, which was passed in 2021.[1] The first phase in docket UM 2225 resulted in Commission procedural rules for filing Clean Energy Plans (CEPs). Some parties to the UM 2225 docket expressed interest in further process to better understand Commission expectations in order to acknowledge CEPs, as well as expectations for enforcement and accountability on the electric utilities. When Oregon passed HB 2021 two years ago, the new law's 100% emissions-free electricity generation targets were some of, if not the, most ambitious emissions reductions standards in the United States. Just as radical was the law's acknowledgment of the historical and ongoing environmental injustices inherent in utility regulatory decision-making that continue to negatively impact environmental justice communities' wealth, health, and economies.

[1] *See* UM 2273 – Investigation into HB 2021 Implementation Issues, Order No. 23-059 (Feb. 23, 2023).

Accordingly, PUC Staff recommended that the Commission open a docket to address the remaining implementation issues related to the content of the CEPs. The Commission opened docket UM 2273 solicited comments from stakeholders and utilities in UM 2273 on how best to address some of these issues. As a result, the Commission issued Order No. 23-194 (Scoping Order) offering the opportunity for intervenors to file legal briefs supporting their arguments for action they believe the Commission must take for a robust CEP acknowledgement decision-making process, while also providing its preliminary analysis that the Legislature delegated to the Commission the broad authority to make acknowledgment analyses and determinations.

In this Brief, CUB responds issues and questions raised in Order No. 23-194 (Scoping Order) of this docket, specifically:

- whether renewable energy certificates (RECs) can and should be retired for HB 2021 compliance;
- whether the Commisison should give guidance on the meaning of "public interest" in HB 2021;
- the impact of statutory policy statements n HB 2021 implementation; and
- brief thoughts on whether the time is right to address HB 2021 Sec. 10 ("Cost cap for electric utilities").

However, before CUB weighs in on issues raised in the Scoping Order, we have included a section on CUB's understanding of the history of clean energy laws in Oregon. We intend this information to provide a foundation for this brief and hope it provides helpful information for the scoping process.

## II. BACKGROUND ON OREGON CLEAN ENERGY POLICY

Over the years, the Oregon Legislature has passed a series of laws that address clean electricity. SB 1149 (1999), SB 838 (2007), and SB 1547 (2016) developed programs that were based on renewable energy certificates (RECs). Cap-and-trade bills did not pass in 2019 and 2020 but were emissions-based programs that ultimately led to HB 2021, also an emissions-based system. CUB participated in the negotiations of all these programs, and what follows is our understanding of what they do and how they interact with each other. CUB offers these thoughts in the spirit of advancing a shared understanding of the history and evolution of climate-related policy in Oregon, which CUB hopes will be helpful to this UM 2273 process. After providing this high-level history, CUB offers legal analysis on the REC-related issues addressed in the Commission's scoping memorandum in this docket.

### A. Oregon's Clean Energy Bills

In 1999, Oregon passed **SB 1149**, an alternative to Enron/Portland General Electric's (PGE)'s deregulation proposals. The bill was based on the Fair and Clean Energy Model that was proposed by CUB, the Northwest Energy Coalition (NWEC), Renewable Northwest Project (now called Renewable Northwest (RNW)) and others in the PUC docket UE 102 (the Enron deregulation investigation). One provision of the bill required the PUC to establish a "Portfolio Options Committee" (POC) which would develop rate options for residential and small commercial customers, including an option to voluntarily purchase renewable power. In addition, it established a "public purpose charge," part of which would go to fund the "above-market cost of renewables." At the time, renewables were more expensive to develop than fossil fuel generation. The marginal resource to serve new load at the time – the least cost resource – was generally identified as a natural gas turbine. The renewable provisions of SB 1149 were designed to address this high cost. The public purpose charge would go to buying down the cost of renewables so PGE and PacifiCorp could pursue renewables even though they were not the least cost resource.

The voluntary renewable program developed by the POC allowed customers to support additional renewable investment. It was designed to be a load- or consumption-based system that used RECs (REC-based system). At the time, RECs were often described as representing the above-market cost of renewables. Accordingly, if it cost 7 cents/MWh to develop wind energy, the market price for natural gas generation was 5 cents/MWh, then the REC should cost 2 cents. Customers buying the RECs to serve this voluntary renewable program would pay the above-market cost and allow developers to develop the renewable resource. After recovering the above-market premium by selling the REC, the developer would be left with a resource that was equal in cost to the marginal resource. RECs allowed customers to overcome the biggest barrier facing renewable generation: its high cost. Voluntary programs are attractive because they allow customers to offset their fossil fuel usage and reduce their personal carbon footprint. Purchasing a REC allowed the person paying the premium – paying the difference between fossil generation and clean generation – to claim the clean energy attributes. Claiming carbon reduction by purchasing a REC only makes sense if that REC is associated with a reduction in carbon emissions. And this was assumed to happen because the power from the underlying resource that produced the REC would, once added to the grid, displace fossil generation.

**SB 838,** passed in 2007, developed the Oregon Renewable Portfolio Standard (RPS). It was designed to operate as a REC-based system. The purpose of SB 838 was to drive new electric investment towards renewable energy by establishing requiring utilities to have 25% of their system served by renewables by 2025. It is important to recognize that it was designed to drive new investment, so it did not include all existing renewables as "qualifying." This was controversial considering the vast amount of hydropower in the region and both PGE and PacifiCorp had a significant amount of Mid-Columbia hydropower dedicated to them under contracts. Allowing historic hydropower would mean that the standard did not require very much new investment. This created a distinction between renewable electricity and "qualifying renewable electricity" for RPS compliance purposes. While the intention was to affect future development, utilities wanted to include some of the current renewables that were already in customer rates (aka credit for early action).

Ultimately SB 838 set a somewhat arbitrary operational date, January 1, 1995, as the dividing line between qualifying renewable resources and those renewable resources that did not qualify.

Again, this was meant to drive investment in new renewable energy resources. It limited the use of unbundled[2] RECs to 20% of the requirements and it allowed unlimited banking of RECs meaning a REC produced in one year can be saved and used to comply with the RPS in later years. The unlimited banking was intended to create an incentive for early action by a utility. Utilities could build renewables faster than the law required, bank the RECs, and use those banked[3] RECs to comply as the standard grew (but the oldest RECs in the REC bank had to be used first).

In 2016, the Oregon Legislature passed **SB 1547** which phased out coal-fired generation and ramped up the RPS to 50%. It maintained the unlimited banking for RECs that were issued before the bill's effective date. While other RECs generally had a five-year life, in order to encourage early investment in renewables, it allowed some RECs from new projects to have an unlimited life (casually referred to as "golden" RECs). Because it created different lives for different RECs, it eliminated the requirement that the oldest RECs were used first. On its simplest terms, SB 1547 saw carbon reduction by phasing out coal and replacing that coal with renewables. However, because much of the coal came from out-of-state coal plants, much of the coal could still generate and serve customers in other states. One critique of the coal-to-clean law was that it did not actually lower emissions, it simply shifted them to other states. The economics are a little bit more complicated. However, for multi-state utility PacifiCorp, SB 1547 put economic pressure on other states to consider removing coal from their portfolios because it set a hard deadline for Oregon's economic exit from coal plants.

In the early days, renewable resources cost more than fossil fuel generation, but those high costs were up-front capital costs. This meant that fossil fuel generation was the marginal resource to serve new load. However, in short-term markets, because renewables had no fuel costs, they were

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[2] An "bundled REC" is a REC retains the electricity generated that created the REC. An "unbundled REC" has been stripped away from that electricity for compliance with an RPS. ORS 469A.005(4) & (14).

[3] A "banked" REC means a bundled or unbundled REC not used to comply with the RPS in a calendar year and is carried forward for compliance in a subsequent year. ORS 469A.005(2).

lower cost than fossil fuels and would displace the fossil generation. Voluntary programs and RPS programs helped overcome the high up-front costs of renewables, enabling them to be built and ultimately displace fossil fuel generation.

However, by the time SB 1547 passed, the capital cost of renewables had fallen and it could no longer be assumed that the marginal resource for new load was fossil generation. If renewables are the marginal resource, then the economics change. Offsetting coal with renewables in Oregon reduced Oregon's emissions, but if the coal still existed and was a cheaper power source, it would offset the need for renewables to meet load growth in other states. If renewables are the marginal resource, a REC no longer represents the above-market cost, because there is no above-market cost. While renewables sold in short-term markets will still displace fossil generation (without fuel costs, they still have a price advantage), in states with clean energy laws, renewables built to meet load growth may simply displace alternative renewables also available to meet that load growth. And renewables built to replace out-of-state coal could see emissions be shifted to other states that would have otherwise been served by developing new renewables. Further, between SB 838 and SB 1547, the state of Oregon implemented an economy wide emissions reporting program which tracked actual emissions emitted in Oregon each year. This meant using a banked REC from a previous year did not reduce the reported emissions of a utility.

While bills to launch an Oregon **cap-and-trade program** were attempted in 2019 and 2020, but did not pass, the effort resulted in an agreement on how to treat electricity under such a program. The cap-and-trade bills focused on emissions, not RECs, and were built off the DEQ's emissions reporting program. The cap-and-trade legislation would have created an economy-wide program that was focused on reducing emissions within the state. The state would establish a declining annual emissions limit and issue emission allowances equal to that limit. Electricity generators had to produce allowances that were equal to their emissions. The early cap-and-trade negotiations and the shared understanding that the program would be emissions-based set the stage for the negotiations that ultimately culminated in HB 2021's passage.

Allowances could be used as offsets. Rather than reduce emissions, a utility could purchase allowances from other sources that reduced emissions beyond their share and therefore had allowances to sell. Hydro generation that was pre-1995 was non-emitting and did not require an allowance. Emissions from gas or coal generation had emissions and required allowances. A renewable resource that had its REC stripped off and placed in the REC bank, was recognized as non-emitting. A REC that was associated with power generated in a previous year and placed in the REC bank was irrelevant. It neither created nor reduced current emissions.

**HB 2021**, passed in 2021, was originally developed by environmental justice communities. When it was brought before a wider group of stakeholders there was a great deal of discussion over whether 100% clean energy should be defined by counting RECs or by eliminating emissions. Advocates of an emissions-based program (i.e., one that does not use RECs) won the argument and that was what went into the bill. Essentially, the electric sector under HB 2021 is regulated as a cap-and-no-trade system. Compliance required eliminating emissions as tracked by Oregon's emission reporting system.

In contrast to HB 2021, a **REC-based** 100% clean system is a load-based system that requires utilities to retire enough RECs to equal their load each year. Fossil fuel generation could be allowed as long as the generation was offset with a REC. A utility's IRP would focus on optimizing both the least cost/least risk way to meet load and the least cost/least risk way to secure enough RECs to offset that load. Because solar would likely be the least cost way to secure RECs and gas-fired generation would likely be the least cost way to serve winter peak, it is likely that an optimized system would still use gas to meet winter peak but would use solar RECs to offset those emissions. The emissions created by using gas to serve winter peak would still exist but would theoretically belong to whoever bought the power that had become detached from the solar when the utility banked the REC even though the gas generation was dispatched to meet the utility's winter peak. The communities near the gas-fired plant would still be breathing GHG emissions associated with the gas plant. A REC-based 100% clean program would also require revisiting the definition of renewable to prevent a huge overbuilding of the Northwest's energy grid due to its vast hydro resources (and some nuclear) that do not count towards the RPS.

An **emissions-based** 100% clean system solves some of the problems that exist with a 100% clean REC-based system. We do not have to worry about hydro or nuclear power. Because it does not use fossil generation combined with offsets, air pollution from gas plants is not an issue. At the same time, an emission-based system is harder. 100% clean based on emissions means that utilities have to solve the challenge of meeting winter peak load (think 7 am on January 15) with non-emitting power rather than gas plants offset with banked RECs. But if this country is going to get to 100% clean, the winter capacity issue needs to be solved. If the goal is to move to a non-emitting system, it makes more sense to track emissions and focus regulation on reducing emissions.

When stakeholders were negotiating HB 2021, there was clear agreement to use an emissions-based system, not a load-based system. This was a key point in the negotiations. Some parties opposed the bill because RECs were not part of the program. HB 2021, Section 13 makes it clear that the emissions associated with electricity is based on the underlying resource was a clear provision written into the law to make clear that this was an emissions-based system.[4] The bill regulated emissions, not RECs.

### B. How do emissions-based and REC-based systems interact?

It is important to recognize that HB 2021 did not repeal the 50% RPS. That law is still in place. Utilities still have REC banks and still need to retire RECs to meet the requirements of the RPS. California also has an RPS and a cap-and-trade program that is emissions based. It is

[4] HB 2021, Sec. 7 (2021).

important to recognize how these programs fit together. CUB offers three scenarios of how a utility operates when it is subject to both an RPS and an emissions-based program.

*If the utility uses the power that generates the REC*. An Oregon utility is subject to both Oregon's RPS and Oregon 100% non-emitting standard. For renewable development this means that if an Oregon utility has a renewable resource that resource produces bundled RECs. The utility will strip off the REC and place them in the REC bank, where depending on the vintage of the RECs, the REC have either an unlimited life or a 5-year life. The power will then be used to serve load or will be sold on the market. If it is used for serving the utility's customers, then it would be included in their DEQ emissions reporting as non-emitting power. The utility gains a REC to use to comply with the RPS and gets a unit of power that is emission-free for purposes of the emission standard.

*If the utility sells the power to a California utility*. Assume power is being produced on a mild day, the utility strips off the REC, places the REC in the REC bank and the utility offers the power into the day ahead market where it is dispatched to a California utility. That California utility is subject to California's RPS, but the power produced in Oregon would not have a REC and would not be considered an eligible renewable for purposes of the California RPS. But because the underlying resource is non-emitting, the California utility would not need to purchase a cap-and-trade allowance to offset the emissions. This makes sense because there are no emissions being created. As regional markets develop, they will help identify the source of power – the source of the underlying resource. If a California utility is looking for power in the day-ahead market and has a choice between gas-fired generation from Utah, and a non-emitting REC-less generation from Oregon, it would prefer the Oregon power because it would not need to purchase a carbon allowance under cap-and-trade. And this is exactly what cap-and-trade is designed to do: make fossil fuels generation more expensive so utilities prefer non-emitting resources.

*If the utility purchased power from a California utility.* Assume an Oregon utility purchases power from a California utility to serve load in the early afternoon when California's solar is at its peak. The California utility will likely take the bundled solar power and strip off the REC for compliance with California's RPS. Because of HB 2021, Oregon utilities want to reduce emissions and will be looking to reduce dispatch from gas plants. So the Oregon utility could purchase power that has no REC and cannot be used for compliance with Oregon's RPS but comes from a solar facility, so it is non-emitting. Oregon backs off dispatch of a gas plant, reducing emissions.

As this brief will address, HB 2021 was always contemplated as an emissions-based program, not a load-based program. This interpretation aligns with the clear intent of the legislation and will ensure that Oregon's electricity system is 100% emissions-free rather than offset by RECs.

## II. DISCUSSION

### A. The Oregon Public Utility Commission does not have the authority to retire renewable energy credits.

In the Scoping Order, the Commission asked:

> Can and should the Commission require retirement of RECs to demonstrate compliance with HB 2021? Does the answer depend on how the Oregon Department of Environmental Quality (DEQ) interprets and implements ORS 468A.280? If the Commission does not require retirement of RECs, can and should it otherwise restrict their use by utilities subject to HB 2021?[5]

The PUC also invited comments on the DEQ's greenhouse gas emissions methodology and its relevance to the Commission's approach to HB 2021 compliance determinations and treatment of RECs.[6] CUB maintains that RECs, components of Oregon's RPS, have no role in and no impact on the emissions standards contemplated in HB 2021 and the Commission does not have the authority to require utilities to retire RECs used for HB 2021 compliance. However, the Commission has the authority to place REC-related conditions on utilities for their compliance with Oregon-based voluntary customer programs and the RPS. **The PUC is not directly authorized to require retirement of RECs from energy generated for HB 2021 compliance.**

[5] UM 2273 - Order No. 23-194 at 3 (June 5, 2023) ("Scoping Order").
[6] Scoping Order at 3.

CUB supported the emissions-based system, while acknowledging that it would be harder to implement because CUB felt that ultimately, we need a system that produces emissions-free electricity when customers use electricity. Whether a resource had a REC or not was what the program was concerned about. The concern was whether the resource directly produced emissions when it generated the power.

HB 2021 states its requirements "do not replace or modify" Oregon's RPS requirements. An emissions-based program, it requires that the electricity generated "shall have the emission attributes of the underlying generating resource."[7] It directs utilities to provide annual emissions reports to the Oregon Department of Environmental Quality (DEQ) and then DEQ reports its findings to the Commission using DEQ's methods.[8] DEQ must verify projected GHG emissions reductions forecasted in a utility's CEP and report its findings to the PUC and the electric company seeking acknowledgment of a CEP.[9] The Commission must use the annual emissions reported from DEQ "to determine whether or not the retail electricity provider has met the clean energy targets."[10]

The Oregon Legislature has vested the Commission with the broad regulatory authority to balance the competing interests of customers and utility shareholders. "This delegation provides the Commission with "the broadest authority—commensurate with that of the legislature itself—for the exercise of [its] regulatory function."[11] Further, that "the commission shall make use of the jurisdiction and powers of the office to protect such customers, and the public generally, from unjust and unreasonable exactions and practices" and the authority to "to do all things necessary and convenient in the exercise of such power and jurisdiction."[12] However, this authority is not without

[7] HB 2021, Sec. 7.
[8] *Id.* at Sec. 5.
[9] ORS 469A.420(1)(a-b).
[10] ORS 469A.420(4)(b).
[11] UM 989, *In the Matters of The Application of Portland General Electric Company for an Investigation into Least Cost Plan Plant Retirement*, Order No. 08-487 at 4 (Sept. 30, 2008) (citing *Pacific Northwest Bell Tel. Co. v. Sabin*, 21 Or App 200, 214, 534 P2d 984, rev den (1975)).
[12] ORS 756.040(1–2).

limits. The Commission's authority is bound by limits inherent in the federal and state constitutions.[13] Additionally, as an administrative agency, the Commission only has authority to the extent that it has been explicitly delegated such authority by the legislature.

### 1. *The plain language of HB 2021 does not require REC retirement.*

In order to determine whether the Commission has been explicitly given the authority to require REC retirement for HB 2021 compliance, we must engage in statutory interpretation analysis of HB 2021's plain language. Statutory interpretation requires discerning the intent of the legislature.[14] The first step in doing so is examining "both the text and context of the statute."[15] If the legislature's intent is not clear from the text and context inquiry, the next step is considering legislative history.[16] If legislative intent is still unclear, the next step is to apply maxims of statutory construction.[17] In *State of Oregon v. Gaines*, the Oregon Supreme stated:

> ... there is no more persuasive evidence of the intent of the legislature than "'the words by which the legislature undertook to give expression to its wishes.'" *State ex rel Cox v. Wilson*, 277 Or 747, 750, 562 P2d 172 (1977) (quoting *U.S. v. American Trucking Ass'ns*., 310 US 534, 542-44, 60 S Ct 1059, 84 L Ed 1345 (1940)). Only the text of a statute receives the consideration and approval of a majority of the members of the legislature, as required to have the effect of law. Or Const, Art IV, § 25. The formal requirements of lawmaking produce the best source from which to discern the legislature's intent, for it is not the intent of the individual legislators that governs, but the intent of the legislature as formally enacted into law.[18]

Under Oregon law, the text and context of the statute in question are given the primary weight in the three step *State v. Gaines* statutory interpretation process.[19] When examining a statute's text and

[13] OPUC Order No. 08-487.
[14] *Portland Gen. Elec. Co. v. Bureau of Labor & Indus*., 317 Or 606, 610 (1993), citing ORS 174.020.
[15] *Id*.
[16] *Id*. at 611.
[17] *Id*. at 612.
[18] *State v. Gaines*, 346 Or 160, 171 (2009).
[19] *In re Portland General Electric Company, Application for Transportation Electrification Programs*, OPUC Docket No.UM 1811, Order No. 18-054 at 7 (Feb. 16, 2018); *in re PacifiCorp, dba Pacific Power, Petition for Declaratory Ruling Regarding ORS 757.480*, OPUC Docket No. DR 47, Order No. 14-254 at 4 (Jul. 8, 2014).

context, the Commission gives words of common usage "their plain, natural, and ordinary meaning."[20]

Applying *State v. Gaines* and looking to the plain meaning of the text and context of HB 2021, CUB agrees with the Commission that "with a statement so specific to the issue in the operative language of the statute, we do not see that we have discretion to interpret HB 2021 to allow us to insert a requirement that RECs be retired to demonstrate compliance."[21] The statute is explicit that "[n]othing in sections 1 to 15 of this 2021 Act may be construed as establishing a stnadard that requires a retail electricity provider to track electricity to end use retail customers."[22] A plain language reading of this section, as directed by *State v. Gaines*, renders it clear that HB 2021 was never intended to use RECs for RPS compliance. As the Commission has indicated in its scoping memo, HB 2021's directive is unamibuous and the legislature's intent is clear. The Commission may end its statutory intepretation analysis here. However, should the Commission wish to continue its statutory interpretation analysis, CUB submits that pertinent legislative history supports CUB's conclusion and does not run counter to the legislature's unambiguous plain language.

### 2. ***Pertinent legislative history supports CUB and the Commission's conclusion that HB 2021 does not require REC retirement.***

After examining the plain language of the statute, the next step in statutory interpretation is to consider legislative history. As can be seen in the quotes highlighted in CUB's introduction, many parties to this proceeding—including several that now assert HB 2021 requires REC retirement—were all in agreement that HB 2021's express language was meant to track emissions, not RECs. The Commission should not be persuaded by parties attempt to now re-legislate HB 2021 and impute meaning into its terms that do not exist.

[20] OPUC Order No. 14-254 at 4 citing *Portland Gen. Elec. Co. v. Bureau of Labor & Indus*., 317 Or 606, 859 (1993).
[21] Scoping Order at 3.
[22] HB 2021, Sect. 3(2).

Legislators and bill sponsors have been clear since HB 2021's earliest iterations that the program was designed to count emissions, and not be based on REC retirement. Representative Pam Marsh, HD 5, a Chief Sponsor of the bill, made it clear HB 2021 was emissions-based in her testimony before the Oregon House Committee on Revenue:

> While they are instructed to pursue non-emitting electricity sources, the bill is technology neutral, allowing the utilities to develop a variety of clean energy sources, as well as energy efficiency, demand response, or other end-user strategies that lead to reduced emissions.[23]

Proponents of the bill, including PacifiCorp and Portland General Electric (PGE), reaffirmed that it was the entity generating the emissions that was the focus of regulation. The two electric utilities stated that HB 2021 "sets clear goals and timelines for reducing greenhouse gas emissions from customer power."[24] In their written testimony, the NW Energy Coalition (NWEC) spoke exclusively on the nature of the emissions-based standard, "HB 2021 takes an emissions approach, and since that approach has received a much more thorough discussion this session, my comments will focus on that emissions-based approach."[25] Renewable Northwest (RNW) agreed, testifying that HB 2021 "presents an improved emissions-plus-planning approach to achieving 100% clean electricity" and that electricity providers would be required "(1) to reduce their system emissions in order to conform with defined targets and (2) to establish plans every two years demonstrating how they will achieve those targets." Notably, RNW acknowledged that HB 2021 stopped short of including RECs:

> And after significant negotiation, stakeholders have worked out an accounting approach that stops just short of requiring proof of delivery of clean power plus a renewable energy certificate ("REC") to end users – an issue that has caused difficulties in implementing Washington's Clean Energy Transformation Act.[26]

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[23] Oregon State Representative Pam Marsh, transcription of 5/13/21 HB 2021 oral proponent testimony, Or. H. Comm. on Rev. (May 13, 2021) .
[24] Pacific Power and Portland General Electric, Written Testimony in Support of HB 2021, Or. H. Comm. on Rev (May 14, 2021).
[25] NW Energy Coalition, Testimony in Support of HB 2021, Or. H. Comm. on Rev (May 13, 2021).
[26] Renewable Northwest, "Support for HB 2021A", Or. H. Comm. on Rev. (May 14, 2021).

Even opponents of the bill expressed their frustration with an emissions-based standard. Jake Stephens of NewSun Energy wrote:

> The simple truth is this: If the choice was RPS vs Emissions 10 or 20 years ago, it wouldn't matter so much. I'd support either (conceptually). But it's too late. The 2020s are the most important decade in the history of the world. Action is required. Progress is required. In 2022, 2023, 2024 – not 2028. The emissions-based approach—at this point—has costs, risks, delays, uncertainty that are unnecessary, and undermine your goals, undermine the outcomes.[27]

The Community Renewable Energy Association commented that increasing the RPS standards was a better policy than HB 2021's emissions-based programs.

> "We believe that increasing the current Renewable Portfolio Standards now is the most expedient method for accelerating the decarbonization of the grid. We recognize that an emissions based approach is a more comprehensive strategy but that system will take time to implement."[28]

Similarly, the Oregon Solar + Storage Industries Association (OSSIA) argued for a stronger RPS policy instead.

> "Utilities would receive benefits from renewable energy without paying for them (through Renewable Energy Credit (REC) attributes). Currently, utilities are not receiving the emissions reduction attributes of the RECs they receive when purchasing certain types of power. The -1 language would give those benefits to the utilities for free, instead of requiring compensation to project owners for additional benefits, devaluing renewable projects and the REC market as a whole. If there is a desire to address this question, it is a complicated issue that is best determined and decided by the PUC, not by prescriptive legislation."[29]

As conclusively demonstrated, both HB 2021's express terms and relevant legislative history support CUB's conclusion.

### 3. *Additional policy considerations support CUB's conclusion*

Additional policy considerations dictate that HB 2021 is an emissions-based program. The Commission's HB 2021 compliance determinations "are informed by the emissions verification that

[27] NewSun Energy, Testimony in Opposition to HB 2021, Or. H. Comm. on Energy and Env. (March 23, 2021).
[28] Community Renewable Energy Association, Testimony on HB 2021, Or. H. Comm. on Energy and Env. (Apr. 5, 2021).
[29] Oregon Solar + Storage Industries Association, Written Testimony Opposing HB 2021, Or. H. Comm. on Energy and Env (March 17, 2021).

HB 2021 assigns to DEQ," without PUC involvement.[30] And finally, HB 2021, Sec. 13 states that HB 2021 does not "replace or modify" the requirements of the RPS laws.[31] While the Commission has been delegated broad regulatory authority to oversee investor-owned utilities, the Legislature was clear that it did not intend to alter RPS requirements with HB 2021.

The Oregon Department of Energy (ODOE) tracks Oregon's RPS goals and certifies the facilities that generate power from RPS-eligible renewable energy resources.[32] ODOE approves the energy sources that may be used to comply with the RPS.[33] ODOE was directed to establish Oregon's REC system in consultation with the PUC.[34] The Western Renewable Energy Generation Information System (WREGIS ) issues Renewable Energy Certificates (RECs) for the Oregon-certified energy facilities.[35]

Pursuant to ORS 469A.065, utilities must develop and file an implementation plan for RPS compliance with the Commission which are reviewed every two years.  The plan must include annual targets for acquisition and use of qualifying electricity, and an estimated cost of meeting those targets which includes a least-cost/least-risk planning analysis. The Commission may acknowledge an implementation plan subject to conditions. The Commission also oversees regulation of utility programs that allow residential customers voluntarily enroll in renewable resource options like a green power rate.[36]

Both ODOE and the PUC have authority over RECs. ODOE is the manager of Oregon's RPS program. And the PUC helped ODOE develop REC system and is also sole authority of Oregon's voluntary customer programs, like the green power rate. Accordingly, only ODOE has the authority

[30] Scoping Order at 3 (see HB 2021, Sec. 7 and Sec. 5, respectively).
[31] ORS 469A.460.
[32] ORS 469A.027, -130.
[33] ORS 469A.025(9).
[34] ORS 469A.130.
[35] OAR 330-160-0020.
[36] OAR 860-038-0220. ORS 469A.205.

to manage RECs, including provisions around their retirement. CUB reiterates again, nothing in HB 2021 changed the RPS, including ODOE's authority over the RPS.

As a major party involved in the negotiations around HB 2021, CUB has no doubt that HB 2021 was an emissions-based regulatory system that did not require retirement of RECs. We continue to believe that the law as written reflects this understanding. It is an approach that requires real emission reductions and does not allow RECs to be used as offsets to eliminate those emissions. Offsetting emissions is what creates the need to assign those emissions to the REC-less power from the source that is itself, non-emitting. CUB believes that SB 1547 and HB 2021 were well-designed and can work together while keeping load-based RECs removed from HB 2021's emissions-based compliance at the same time, CUB supports the Commission's intention to consider whether there are double-counting impacts on the programs it regulates.[20] In this changing policy landscape with increasing electricity rates, there is no harm in making sure customers are protected from unnecessary costs.

### B. The Commission has long held the authority and discretion to determine what is in the "public interest" for the protection of customers.

HB 2021, Section 5(2) states the Commission shall acknowledge a utility's Clean Energy Plan if it is found to be in the public interest.[37] The Legislature directed the Commission to consider six factors in its "public interest" analysis, including a catchall provision: any other relevant factors as determined by the Commission.[38] Parties have requested guidance on how the Commission expects to make a "public interest" determination, especially the "economic and technical feasibility" provision.[39] The Commission responded:

> Initially, we observe that these are general factors, with significant discretion left to the Commission, and that these factors may be better suited to discussion after having been applied to specific facts in our initial CEP review. However, we are open to briefing from

[37] ORS 469A.420(2).
[38] *Id.*
[39] Scoping Order at 4; UM 2225, Order No. 23-061 at 5.

> parties on guidance that may be appropriate for us to give to narrow and streamline how parties approach initial CEP review.[40]

CUB is inclined to agree. As stated in our Comments, regulating in the public interest is the Commission's core function.[41]

The Commission has asked if it should give guidance on its interpretation of "economic and technical feasibility" or other specified factors in HB 2021 Section 5(2), before applying the "public interest" criterion for CEP acknowledgment, and whether the Commission should pre-determine other relevant factors for purposes of Section 5(2)(f).[42] The Commission has long held broad regulatory authority to determine what is in the public interest and that while it does not have to provide guidance on how it may make its determination, , it may do so if it chooses under Oregon law.

With HB 2021's emissions-reduction targets also come HB 2021's environmental justice, equity, and community benefits considerations, as well as parties who represent these ratepayer communities. But rather than issue specific guidelines for a general public interest determination for HB 2021 compliance, beyond what the Legislature has tasked to the Commission in HB 2021, the public interest analyses are best made on a case-by-case basis contemporaneous with a utility's specific CEP filing. This has been the practice of the Commission and is important to enable a contemporary understanding of the public interest at the time of review of a utility filing.

Relying on the Oregon Supreme Court's decision in the seminal statutory construction case *State of Oregon v. Gaines*, the Commission has previously analyzed the word "consider" in a law, finding the plain meaning of the word makes the statutory directive clear. In Order No. 18-054, the Commission found that "the legislature's use of the word "consider," read in its immediate context, makes clear that we are to take in account these factors during our review, but that we retain

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[40] Scoping Order at 5.
[41] UM 2273, CUB's Comments at 1 (Apr. 21, 2023).
[42] Scoping Order at 2.

discretion in our decision-making whether to approve a program."[43] The Oregon Attorney General's Office has found that when the Legislature has delegated authority to an administrative agency, it gives the agency discretion to determine how best to implement the law, finding "[t]he use of a delegative term reflects a legislative decision to entrust policymaking responsibility to an executive agency subject to the broad policy boundaries established by the statutory scheme."[44]

The Legislature has vested the Commission with broad regulatory authority, including the delegation to determine what is in the public interest. While the Legislature has enacted several laws directing the Commission to consider certain factors in its decision-making, including public interest factors like in HB 2021, it has not issued a strict definition of "public interest', seeing fit to leave that determination to the Commission. This delegation of authority makes sense in the context of the Commission's broad authority granted by the Legislature.

The Legislature offered guidance on what can constitute the public interest when it included the subsections as considerations HB 2021, Section 5(2)(f). And the plain language of the law shows that the Legislature did not want to be overly prescriptive, only that the Commission consider factors the Legislature determined were in the spirit of the law. Nor did the Legislature direct the Commission to be rigid in its public interest analysis, given the catchall provision in HB 2021, Section 5(2)(f). Accordingly, we do not believe the Commission must give guidance on its interpretation of the public interest factors listed in Section 5, and nor should it. Further, public interest determinations are necessarily fact-based and, in this case, specific to the individual CEP and will be considered in those dockets. The plain language of Section 5(2)(f) is explicit in what the Legislature specifically wanted the Commission is to consider, while also recognizing the Commission's authority to make its own determination.

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[43] UM 1811, Order No. 18-054 at 8–9 (Feb. 16, 2018) (citing *State v. Gaines*, 346 Or 160, 171–172 (2009)).
[44] Office of the Attorney General, State of Oregon, Opinion No. 8181, 45 Or. App. Atty. Gen 98 (Nov. 4, 1986).

It is important to remember that what is in the public interest can shift. Six or seven years ago with the focus on moving away from coal-fired generation, connecting to natural gas may have been considered in the public interest, but that analysis would look different today given the policy shifts since then. Given the inevitable malleability of "public interest" and the fact that the Commission generally cannot bind future Commissions through language in an order,[45] to define "public interest" would be counter to the primary role of the Commission as the agency protecting the public's interest. CUB cautions that to do so could do more harm than good. If we start to define some terms and not others, it can leave the impression the Commission values some over others. We also risk finding ourselves spending unnecessary time and resources litigating statutory language whose terms are plainly understood, which can waste a lot of time and resources that would be better spent designing and implementing robust CEPs.[46]

However, we note that this delegation comes with expectations of a shift away from business-as-usual utility regulation: that CEPs will be developed and acknowledged with an environmental justice lens and expectation of public input. The Commission has held robust processes in UM 2225 and UM 2273 to consider what the social expectations of HB 2021 mean and how they should be implemented. Staff has indicated the relevance of the public interest factors and that direct community involvement is necessary.

> Staff also agrees that providing annual information about community impacts and benefits may help the Commission determine whether the utility's plan is in the public interest. HB 2021 §5(2) specifically identifies that environmental and health benefits of greenhouse gas reductions are relevant to the determination of whether the plan is in the public interest... Staff further notes that accurate evaluation of community impacts and benefits cannot be undertaken without direct involvement of the communities that are impacted by the plan.[47]

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[45] See, e.g., in re Electric Utility Purchases from Qualifying Facilities, OPUC Docket No. 1129, Order No. 05-584 at 50 (May 13, 2005) ("We are also not convinced that we have the legal authority to bind future commissions . . . .") and in re Portland General Electric Company, OPUC Docket No. UE 189, Order No. 08-245 (May 5, 2008) ("CUB observes that this Commission cannot bind future commissions, in any event.").

[46] See Order in UM 1811 – Order No. 18-054, litigated "consider".

[47] UM 2225 Investigation Into Clean Energy Plans, *Work Plan Update and Straw Proposal* at 8 (Aug. 9, 2022).

Further, the Commission has signaled it expects to see analyses of the new planning requirements in HB 2021:

> With respect to the new analyses and studies described in these expectations, particularly the Community Benefits Indicators and the Community Lens Study, we anticipate that the Commission, stakeholders, and utilities will learn about the feasibility of these expectations after this first CEP filing. In the event that a utility is unable to meet any of those expectations encompassed by this order, we expect a full explanation of why doing so was infeasible or impractical. Such an explanation is likely to be helpful in the Commission's determination of whether to acknowledge a CEP that may have fallen short of these expectations.[48]

Accordingly, CUB believes rather than the Commission pre-determining public interest factors, it is more appropriate to make those considerations in each specific CEP docket, given the reality that public interest will change over time. And because it is those community members affected by the CEP who are the voices of the public and are well-positioned to explain what is in their interests now and in the future. CUB expects the Commisison will give each HB 2021 public interest factor a close look when reviewing a CEP for acknowledgment, and we expect that analyses to be largely informed by those communities impacted by the CEP.

However, CUB believes it is incredibly important to heed the requests of representatives of communities and interests historically marginalized from utility regulatory decision-making. HB 2021 explicitly addressed protecting. Their requests for more guidance on what the utility needs to show for CEP acknowledgement are understandable and reasonable. The Commission is implementing a new law with looming deadlines and parties are still trying to figure out how utilities plan to meet HB 2021's emissions targets.

CUB concludes that a public interest determination is exclusively within the Commission's determination, and that general guidance around what public interest might mean will be better to investigate within the fact-specific CEPs. However, if environmental justice groups come before the

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[48] UM 2225, Order No. 22-390 at 1 (Oct. 25, 2022).

Commission and ask for more assistance navigating utility regulatory decision-making, in this docket or the next, CUB expects to support those requests and assist in whatever way we can. We would not hesitate to participate in any future proceeding, Phase II in this docket or otherwise, to improve access to this space for environmental justice groups.

**C. Statutory policy statements are not operative provisions of the law but provide guidance when a term or provision of a statute is unclear.**

In response to parties' requests to understand how the Commission will consider HB 2021 Section 2 policy statements, when reviewing CEPs, the Commission asked: "What relevance can and should the statements of policy in HB 2021 Section 2 have to the Commission's implementation of the operative provisions of the law?"[49] Giving an early analysis, the Commission stated they have held that statutory policy statements "generally will not lead us to alter our interpretation of clear language used in the operative sections of the law," but acknowledged that they can be helpful in guiding their "interpretation of ambiguous or delegative statutory provisions and informing our selection of discretionary initiatives to pursue."[50] CUB agrees with this conclusion.

As discussed above, when interpreting a statute, the Commission will apply the statutory interpretation analysis of *State of Oregon v. Gaines*. It will look to the operative provisions of the law and try to figure out the directive from the plain language. If the language is still unclear, the Commission will next look to the context of the statute, like policy statements or testimony. This context allows the Commisison to take a step back and look at the big picture to best discern the meaning of the statute at issue.

Policy statements, just like any statutory language, give the Commission authority and discretion to act in ways (and consider factors) that they may not have otherwise had. However, they are not operative provisions but serve to provide context when terms or phrases in the law are

[49] Scoping Order at 5.
[50] Scoping Order at 5 (citing *In the Matter of Small Scale Renewable Energy Projects Rulemaking*, Docket No. AR 622, Order No. 21- 464 at 5-6 (Dec. 15, 2021)).

unclear. To the extent that ambiguity regarding the plain language of statutory language remains, the Commission should endeavor to ensure the language is being implemented in a manner that furthers the policy statements. Further, HB 2021 implementation, including any future rulemaking proceedings, should be conducted in a manner that ensures HB 2021's policy statements are met.

**D. The cost cap issue does not need to be addressed yet but can be if needed.**

The Commission has asked whether there are "threshold issues of interpretation related to HB 2021, Section 10 ("Cost cap for electric utilities") on which advance Commission guidance would be useful and beneficial?"[51] CUB does not see the cost cap as a major issue that should be addressed now. Rather, defining the cost cap could be addressed in the situation where the cost cap is likely to be reached in the medium term. However, if the Commission or other parties feel that the cost cap needs to be addressed in this proceeding, CUB believes the cost cap examples in the Scoping Order could benefit from further discussion. CUB offers the following questions as some that may be answered without further factual development:

- How will resources that straddle RPS and HB 2021 be treated (i.e. if there is a wind resource whose RECs are partially used for RPS, and the remainder is used for HB 2021)?
- What happens if a resource is procured and it wouldn't trigger the cost cap in a certain year, but adding a new resource the next year would trigger the cost cap?

Further, while Section 10 couches the cost cap in terms of "rate impact", it is unclear how exactly the rate impact will be calculated. Is it limited to a year? Section 10(3)(b) allows parties to adjust the cumulative rate impact. Is this something like extending the amortization window? The total rate impact would be the same (if not more due to more ROR being applied), but the annual rate impact would be decreased. Because subsection 4 says 6% annual revenue requirement triggers the cost cap and the Commission can pause compliance, it appears the rate impact is limited to individual years, not considered holistically. It would be helpful to have this clarification.

[51] Scoping Order at 7.

## III. CONCLUSION

CUB agrees with the Commmission's interpretation in the Scoping Order that the PUC is not directly authorized to require retirement of RECs from energy generated for HB 2021 compliance. This is clear from the plain language of the statute and legislative history of HB 2021. The Commission continues have broad regulatory to protect the interests of customers and the policy provisions of HB 2021 can provide guidance in interpreting the law when the statute is unclear. CUB reiterates that given HB 2021's direction to consider past and ongoing environmental injustices caused by utility regulatory decisions, we would not hesitate to participate in any future proceeding to improve access and understanding in this docket for environmental justice groups.

Dated this 25th day of July 2023.

Respectfully submitted,

*/s/Jennifer Hill-Hart*
Jennifer Hill-Hart, OSB #195484
Policy Manager
Oregon Citizens' Utility Board
610 SW Broadway, Ste. 400
Portland, OR 97205
T. (503) 227-1984
E. jennifer@oregoncub.org