

**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.

NOTICE AND MEMORANDUM

Notice is given that the Commission seeks comments from parties on a draft order prepared by the Administrative Hearings Division (AHD) addressing the cost cap provisions set forth in Section 10 of House Bill 2021. The Commission will also hold a Commissioner Workshop to allow for discussion on the draft order and application of those preliminary decisions to a hypothetical scenario.

The procedural schedule for party comments and the Commissioner Workshop is as follows:

<u>Event/Deadline</u>	<u>Date<sup>1</sup></u>
Opening Comments	June 26, 2025
Commissioner Workshop	July 24, 2025, 1:00-4:00 p.m.
Reply Comments	August 7, 2025

**Background**

The Commission identified four issues for the parties to address relating to HB 2021's cost cap provisions:

1. For purposes of calculating applicable investments and costs for HB 2021 compliance, did the Legislature intend to capture only those actions that the utility would not have taken but for HB 2021 compliance, or did it intend to capture a broader category of actions?

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<sup>1</sup> Comments are due by 3 p.m. to provide adequate processing time for the Filing Center. Comments submitted after 3 p.m. will be considered filed on the following business day.

2. Are “forecasted costs” limited to those associated with an action the utility has already taken, or does the term also include anticipated actions not yet taken?
3. How should the HB 2021 cost cap be applied to investments and costs required to satisfy the RPS?
4. Does the cost cap authorization of a pause in utility compliance if the actual or anticipated cumulative rate impact “exceeds six percent of revenue requirement for a year” apply only to individual years, without consideration of past or future years?

Parties submitted opening briefs addressing those questions on May 23, 2024, and reply briefs on June 20, 2024.

### **Comments and Commissioner Workshop**

Based on the parties’ arguments contained in those briefs, AHD has prepared a draft order attached as Appendix A. In light of the complexity of the issues and the need to ensure that the approach ultimately adopted by the Commission is consistent with statutory requirements and administratively feasible, the Commission seeks comments on the draft order. It also has scheduled a Commissioner Workshop to allow discussion of the draft order and its application to a hypothetical scenario, which is attached as Appendix B.

In written comments and at the Commissioner Workshop, the parties are requested in particular to address the following issues to shed light on potential implementation challenges:

1. Counterfactual portfolio
  - a. Utilities should provide more detail regarding how you envision developing the counterfactual portfolio discussed in your joint briefs and in the proposed order.
  - b. Bearing in mind that the draft order does not contemplate treating the results of the counterfactual portfolio comparison as dispositive, all parties should discuss potential pitfalls in the approach described in the draft order. Parties should also describe potential solutions or other opportunities for improvement.

## 2. Hypothetical example

- a. Discuss how the process and analysis described in the proposed order would apply to the hypothetical scenario outlined in Appendix B. Parties should *not* actually perform the analysis that would be needed to support or oppose a Section 10 filing.<sup>2</sup> This is simply an opportunity to use a shared hypothetical example to grapple with the practicality of the draft order’s approach. Parties are also welcome to pose and address other illustrative examples in addition to this requested example. In light of the resource additions and procedural schedules described, how might the proposed order be applied? Some issues to be explored in this context include:
  - i. At what stage in the procurement process would the utilities generally have information sufficient to support including a contemplated action in the non-binding, rough-estimate calculation of “cumulative incremental rate impacts of its existing *and planned* cost-cap-eligible costs and investments vis-à-vis its projected annual revenue requirement” contemplated by the draft order (at page 11) as a means of providing advance warning to the Commission and stakeholders that a utility may be approaching the cost cap?
  - ii. At what stage in the procurement process would (a) the utilities or (b) stakeholders with Section 10 filing rights have sufficient information at a sufficient level of certainty to support a Section 10 filing with respect to a cost or investment?
  - iii. Particularly given the many costs and investments unrelated to HB 2021 compliance that will affect a utility’s rates in the future, as well as the uncertainty regarding the timing of rate cases, how are the utilities, stakeholders, and Commission Staff to develop credible estimates of future annual revenue requirements, i.e., the denominator in a Section 10 determination, bearing in mind that such projections would be binding on neither the Commission, the utility, nor any other

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<sup>2</sup> The hypothetical scenario does not represent a prediction of likely events. It is structured to draw out parties’ assumptions about how the cost cap would be implemented and test the practicality of the proposed order.

ISSUED: May 27, 2025

entity with respect to future ratemaking decisions? Is the utility net present value revenue requirement (NPVRR) methodology sufficient for estimating annual revenue requirement for future years?

- iv. What events are likely to warrant updates to either the numerator or denominator with respect to years for which an exemption has not been granted?
- v. Are there factors the Commission would need to consider for which information is not provided in the hypothetical scenario?

Dated: May 27, 2025.



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Michael Grant  
Administrative Law Judge

**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.

ORDER

**DISPOSITION: DETERMINATIONS MADE WITH RESPECT TO HOUSE BILL  
2021 COST CAP**

In this order, we resolve questions identified in Order No. 24-002 related to the cost cap provisions contained in House Bill 2021 (2021). First, we determine that, in calculating rate impacts, the Commission may only consider costs associated with utility actions for which compliance with sections 1 through 15 of HB 2021<sup>1</sup> was a significant driver. Second, with regard to forecasted or anticipated costs, we conclude that the Commission may only consider projects to which a utility has formally committed. Third, as to the separate cost cap contained in Oregon’s Renewable Portfolio Standard (RPS), we conclude that, if a generating facility is being used for compliance with both HB 2021 and the RPS, an appropriate dollar amount (to be determined on a case-by-case basis) will be counted toward each respective cost cap. Finally, we conclude that the cost cap applies only in individual years, based on the relevant costs experienced in a single year as a percentage of that same year’s revenue requirement.

**I. BACKGROUND**

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<sup>1</sup> While we refer throughout this order to “HB 2021 compliance,” we acknowledge and remind stakeholders that HB 2021’s cost cap applies only to “investments made, costs incurred or forecasted costs estimated by the electric company for the purpose of compliance with ORS 469A.400 to 469A.475” (i.e., sections 1 through 15 of HB 2021). ORS 469A.445(1). This excludes any costs associated with compliance with the statute’s remaining twenty-five sections; for example, energy purchases from small-scale renewable energy projects required by ORS 469A.210 do not count toward the cost cap.

To help mitigate rate increases resulting from HB 2021’s emission reduction targets, the legislature included a “cost cap” provision that allows electric utilities to be temporarily exempt from compliance if the cumulative impact of their compliance costs on customer rates exceeds six percent in a given year. The cost cap, set forth in Section 10 of HB 2021,<sup>2</sup> establishes a process for a Commission investigation to determine the actual or anticipated cumulative rate impact of actions taken by an electric company to comply with HB 2021.

In Order No. 24-002, we identified four areas in need of clarification related to the Commission’s calculation of actual or expected costs of compliance for purposes of the cost cap. First, we noted that the legislature used two different phrases to describe applicable investments and costs. While ORS 469.445(1) describes investments and costs “for the purpose of compliance,” ORS 469.445(1)-(3) refers to whether an investment or cost “contributes to compliance.”

Second, we noted that the legislature requires the Commission to consider not only investments made and costs incurred but also “forecasted costs estimated by the electric company.” We described that forecasted costs could mean both costs yet to be incurred from an action already taken, as well as costs arising from other compliance actions proposed but not yet taken.

Third, we highlighted that HB 2021’s cost cap does not address possible interactions with the cost cap contained in Oregon’s RPS. Similarly designed to help manage costs while encouraging renewable energy adoption, the RPS cost cap provides exemptions if the costs of complying with the RPS exceed four percent of the utility’s revenue requirement in a year. HB 2021 does not clarify how the Commission should treat investments and costs for actions that are required to meet both HB 2021’s emission targets and the RPS.

Finally, we identified uncertainties related to the calculation of rate impacts arising from compliance action. We questioned whether the legislature intended that the cost cap apply only in individual years, based solely on the relevant costs experienced in a single year as a percentage of that same year’s revenue requirement.

To address these uncertainties, we opened the second phase of this docket and asked the parties to provide legal briefing on the four identified issues. The following parties submitted opening briefs on May 23, 2024: Oregon Citizens’ Utility Board (CUB), Alliance of Western Energy Consumers (AWEC), NewSun Energy (NewSun), Portland

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<sup>2</sup> ORS 469A.445.

General Electric Company (PGE) and PacifiCorp (joint brief), Northwest Energy Coalition (NWEC) and Renewables Northwest (RNW) (joint brief), and PacifiCorp (supplemental brief). Reply briefs were filed by the following parties on June 20, 2024: AWEC, NewSun, PGE and PacifiCorp (joint brief), and NWEC and RNW (joint brief).

## II. DISCUSSION

We divide our discussion by the four sets of questions laid out in Order No. 24-002.

### A. **Investments and costs eligible for HB 2021 cost cap inclusion**

Section 10 uses two different phrases to describe applicable investments and costs. Subsection (1) describes an investigation into investments made, costs incurred, or forecasted costs estimated “for the purpose of compliance.” Everywhere else in section 10, the statute refers to whether an investment or cost “contributes to compliance.” Did the Legislature intend to capture only those actions that the petitioner can prove the utility would not have taken, except to meet the requirements of HB 2021 or does Section 10 capture a broader category of actions?

#### 1. *Positions of the Parties*

There is broad agreement among the parties that where an investment or cost is the least cost, least risk option for serving load reliably, regardless of any policy requirements, that investment or cost should not be included in the HB 2021 cost cap. Opinions diverge, however, with respect to actions required by statutes other than HB 2021 or taken for a variety of reasons.

PacifiCorp and PGE (“Joint Utilities”) argue that the statute uses the phrase “contributes to compliance” because it was understood that some investments or costs would be partially recoverable, and that a Commission investigation would be needed to determine what portion of the investment or cost contributed to compliance. The Joint Utilities propose three categories of utility actions: those that do not fall under the cost cap at all; those for which a portion could be included; and those that could be fully included in the cost cap because they are “for the purpose of” reducing greenhouse gas emissions.” In the first, cost-cap-ineligible category they would place, for example, cost-effective energy efficiency and demand response.<sup>3</sup> Partially-includable investments and costs in the Joint

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<sup>3</sup> The Joint Utilities argue that “[w]hile [demand response or energy efficiency] investments or costs could have an effect on reducing emissions, the foundation for these investments pre-date HB 2021, support

Utilities' second category could include, among others, resources acquired or costs incurred to comply with the RPS, the small-scale renewable requirement under ORS 469A.210, or the net metering and community solar requirements of ORS 757.300 and 757.386.<sup>4</sup>

The Joint Utilities propose a two-step analysis in which we would first determine whether an investment or cost was incurred for the purpose of compliance,<sup>5</sup> suggesting that this could be accomplished by asking the utilities to model IRP portfolios as if HB 2021 did not exist; an investment or cost included in both the acknowledged IRP/CEP and this counterfactual portfolio would not be eligible for cost cap treatment because the utility would have proposed it anyway. If the cost or investment occurs only in the acknowledged IRP/CEP, then the Commission would proceed to step two, in which the proponent for including the investment or cost in the cost cap would have the opportunity to show that compliance is at least partly the reason for the investment, and the Commission would determine what portion or percentage of the investment or cost assists the utility in reducing emissions consistent with the targets even if required by a separate, underlying statutory requirement.

According to AWEC, any investment that brings the Joint Utilities closer to their emissions requirements under HB 2021 plays a significant part in their compliance efforts with that law; it does not matter whether the investment may also contribute to other statutory obligations, or even if the investment was pursued primarily for a different statutory obligation. While AWEC believes that costs incurred to meet reliability obligations should be excluded from the cost cap, the same is not true of costs to meet other legal requirements such as the RPS, the Public Utility Regulatory Policies Act, and ORS 469A.210: AWEC contends that each of these legal mandates shares a common purpose with HB 2021, i.e., carbon emissions reduction, and that therefore a purpose of the acquisition of resources to meet these other requirements is to achieve HB 2021 compliance, and the costs of these resources contribute to that compliance.<sup>6</sup>

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traditional notions of resource planning, and would not be made “for the purpose of” reducing emissions,” and that “the Legislature would have known of the requirement to plan for and acquire EE and DR pursuant to either the former public purpose charge in ORS 757.612, or of the modified charge created through HB 3141 in the same legislative session that it adopted HB 2021.” Joint Utilities Initial Br. at 4.

<sup>4</sup> Joint Utilities Initial Br. at 4. Joint Utilities argue that it is reasonable to include such costs in the cost cap because “the fundamental reason for those statutory requirements relate to the same policies underpinning HB 2021: increase renewable energy generation or reduce emissions” and “these investments/costs will reduce emissions from baseline.” *Id.* at 4-5.

<sup>5</sup>*Id.* at 6.

<sup>6</sup> AWEC Opening Br. at 6.

CUB, NewSun, and NWEA/RNW argue that the HB 2021 cost cap applies to costs and investments that would not have been incurred or forecasted but for HB 2021. CUB and NWEA/RNW would exclude from the cost cap any costs and investments incurred to comply with other legal mandates such as the RPS, because such investments would have occurred without HB 2021. NewSun agrees that projects undertaken for compliance with regulatory requirements should not be included in the cost cap, and includes in that category compliance with the Western Resource Adequacy Program (WRAP). CUB notes, however, that the incremental costs of expanding existing programs such as community solar or energy efficiency for the specific purpose of HB 2021 compliance can be considered for cost cap purposes.

## 2. *Resolution*

As the parties acknowledge, in order to answer the question of what investments or costs qualify for inclusion in the cost cap, we must interpret the phrases “for the purpose of compliance with ORS 469A.400 to 469A.475”<sup>7</sup> and “contribute to compliance with ORS 469A.400 to 469A.475.”<sup>8</sup> We recognize that a pure “but-for” test—i.e., an approach that would include actions in the cost cap only if HB 2021 compliance is the sole motivation—is impractical and would render the cost cap meaningless, given the multiple drivers behind almost any utility decision. An interpretation that ignores the rate impact of actions whose primary purpose is HB 2021 compliance because other factors also weighed in favor of the action would be inconsistent with the clear intent of the cost cap. But AWEA’s proposed approach, in which any utility action that reduces greenhouse gas emissions would count toward the cost cap, goes too far in the opposite direction: if a utility’s costs of complying with a host of other obligations exceeded the HB 2021 cost cap, the utility would be exempted from compliance with sections 1 through 15 of HB 2021 without ever having taken an action “for the purpose of” compliance with those sections. Such an expansive interpretation of cost cap eligibility would be inconsistent with the intent expressed in ORS 469A.445(4) to limit the scope and duration—and thus the negative environmental impacts—of exemptions. It would also ignore the cost cap’s explicit limitation to sections 1 through 15 of HB 2021.

To chart a path between these two extremes, we find that for an action to be eligible for inclusion in the section 10 cost cap, compliance with sections 1 through 15 of HB 2021 must be a significant purpose of the action. We are sensitive to the rate impacts of HB 2021 as a whole, and of other statutory requirements. But the Legislature did not

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<sup>7</sup> ORS 469A.445(1).

<sup>8</sup> *Id.*; ORS 469A.445(2)(b); ORS 469A.445(3).

choose to include in the cost cap all of HB 2021's requirements, let alone other obligations. If compliance with sections 1 through 15 of HB 2021 is not among the major drivers behind a cost or investment, we interpret the Legislature's intention to be that the cost or investment does not count toward the cost cap. Where HB 2021 compliance is a significant justification for the expansion of a program, an increase in the capacity of a generation project, or the like, but other drivers exist as well, we will consider the appropriate portion of the cost or investment for inclusion in the cost cap.<sup>9</sup> This interpretation of the statute gives full effect to the statute's limitation of our cost cap proceedings to "accounting for investments made, costs incurred or forecasted costs estimated by the electric company *for the purpose of compliance* with ORS 469A.400 to 469A.475,"<sup>10</sup> while also allowing for such proceedings to include in the cost cap costs or investments that "contribute to compliance" with HB 2021,<sup>11</sup> even if HB 2021 compliance was not the *sole* motivation behind the utility action.

Section 10 contemplates assessments of particular investments and costs, not a whole-portfolio approach. We agree with the Joint Utilities, however, that comparison of a utility's acknowledged IRP/CEP against a "counterfactual" portfolio developed as if HB 2021 did not exist<sup>12</sup> will be a crucial first step in the analysis to determine which costs or investments should be examined more closely. This approach will also provide information for stakeholders regarding the counterfactual cost or investment to which a putative HB 2021 cost or investment should be compared, as well as providing advance warning to the Commission and stakeholders that a utility may be approaching the six percent cost cap threshold. We therefore accept the Joint Utilities' offer to model IRP portfolios as if HB 2021 did not exist, with one modification: Because the cost cap applies only to costs associated with sections 1 through 15 of HB 2021, the "counterfactual" model should remove only the constraints and assumptions required to ensure compliance with those sections, leaving in place all other constraints and assumptions (including those associated with the requirements of sections 16 through 40 of HB 2021) used in development of the preferred portfolio. These counterfactual portfolios, like the IRP itself, are necessarily high-level projections. As a result, inclusion of an action in the counterfactual portfolio, while highly persuasive, would not be dispositive evidence that the action should not count toward the HB 2021 cost cap.

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<sup>9</sup> The drivers of a project can also be considered a project's co-benefits. Nearly any project or program will bring co-benefits to ratepayers and a prudent investment may well bring more benefits than costs. However, offsetting the cost of an investment by its many benefits, as NewSun suggests, would go too far. We aim to estimate a proportional allocation of an investment's costs across drivers.

<sup>10</sup> ORS 469A.445(1) (emphasis added).

<sup>11</sup> *Id.*

<sup>12</sup> Joint Utilities Initial Br. at 6.

On the related question of whether this approach should be applied to the total investment or cost or just to the incremental cost, we find that although section 10, unlike the RPS cost cap set forth at ORS 469A.100 does not explicitly refer to “incremental” costs, it is not possible to determine the “actual or anticipated rate impact for the investment or cost”<sup>13</sup> without reference to the cost of the non-HB 2021-compliant alternative that would otherwise have been included in rates. Subsection 3(a) also directs us to calculate cumulative costs “as adjusted by any change in *net* costs expected or foreseeable at the time of inclusion.”<sup>14</sup> In other words, if we determine that an investment or cost contributes to compliance with ORS 469A.400 to 469A.475, we must also determine what investment or cost it is displacing on a going forward basis – whether those investments or costs are being retired from the revenue requirement or were avoided altogether. We are meant to include in the cost cap calculation only the difference.<sup>15</sup>

## **B. Forecasted costs**

Section 10 contemplates the Commission consider not only investments made and costs incurred but also “forecasted costs estimated by the electric company.” Does the inclusion of “forecasted costs” mean estimated future costs associated with an action the utility has already taken? Or should section 10 be interpreted also to encompass anticipated actions and their anticipated costs (i.e., actions acknowledged in an IRP, CEP, or RFP but not yet taken) and, if so, how much certainty should be required to recognize a cost under Section 10?

### **1. Positions of the Parties**

Joint Utilities state that HB 2021’s “drafters wanted to allow for the investigation of costs from anticipated actions, while at the same time allow for retroactive adjustments once actual costs were known. This method would also provide certainty to the regulated community. For example, in advance of deploying significant capital, stakeholders could initiate investigations on particular investments or compliance strategies to inform cost cap implications of the strategy, or whether the Commission agreed that the action was relevant to the cost cap at all.”<sup>16</sup> Joint Utilities therefore argue that “costs should include estimated future costs to the extent that those future costs would affect rates \* \* \*, as well

<sup>13</sup> ORS 469A.445(3).

<sup>14</sup> ORS 469A.445(3)(a) (emphasis added).

<sup>15</sup> Determining the cost or investment being displaced will require a case-specific analysis; for example, we recognize that the value of a resource to a utility depends on many factors in addition to its nameplate capacity or effective load carrying capacity. This analysis of the cost of an alternative is also distinct from estimating the benefits of an investment.

<sup>16</sup> Joint Utilities Initial Br. at 7.

as anticipated actions and their costs (e.g. actions acknowledged in an IRP that were relatively certain to be accomplished, but not yet taken).”<sup>17</sup> The Joint Utilities suggest that “mere IRP acknowledgement should not be sufficient to trigger an investigation. A higher standard of certainty should be required, for example, a project that has been determined to be on a short-list in an RFP. For projects acquired outside of an RFP \* \* \*, a utility could determine the likely certainty of the project before asking to open an investigation and would, regardless, bear the burden of showing that the cost would likely contribute to compliance.”<sup>18</sup> The Joint Utilities add that “[a] retail electricity provider is not prohibited from making an investment that would cause the entity to exceed the cap – the cap only exempts the provider from further compliance and does not prohibit the investment. Moreover, the cost cap treatment cannot be used as evidence in any proceeding determining actual rate recovery by operation of ORS 469A.445 (5).”<sup>19</sup>

AWEC recommends that Section 10 be interpreted to encompass a utility’s anticipated actions and costs, not just forecasted costs of actions already taken. AWEC argues that if the cost cap includes only costs a utility has already incurred, and the utility reaches the cost cap, then “[e]ither customers will bear any costs above the six percent cost cap, thereby nullifying the customer protection intended by the Legislature, or the utility would bear the cost of exceeding the cost cap, thereby failing to recover the full prudently incurred cost of the resource.”<sup>20</sup> And AWEC notes that we recently “set forth an expectation that resource planning ‘must include greater attention to near-term management of costs and rate pressures.’”<sup>21</sup> AWEC suggests that “in a subsequent proceeding to finally determine if the cost cap is reached, the Commission could use the cost data assumed by the utilities in their IRPs and CEPs as the data on which the Commission would evaluate whether the HB 2021 cost cap is triggered based on a utility’s action plan,”<sup>22</sup> although AWEC acknowledges that “the actual costs a utility would incur to meet its action plan may differ materially from its IRP assumptions.”<sup>23</sup> AWEC suggests in the alternative that we make a preliminary cost cap determination in the context of an acknowledgement order in an IRP/CEP proceeding, “subject to better information on likely actual costs the utility would incur,”<sup>24</sup> such as determining the cost of resources that contribute to compliance with HB 2021 based on the final short list of bids the utility receives. AWEC notes, however, that “RFP bids are time-limited (as may

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<sup>17</sup> *Id.*

<sup>18</sup> Joint Utilities Initial Br. at 7.

<sup>19</sup> *Id.* at 7 n.21.

<sup>20</sup> AWEC Opening Br. at 8.

<sup>21</sup> *Id.* at 8, quoting LC 80 Order No. 24-096, at 22 (Apr. 18, 2024).

<sup>22</sup> *Id.* at 8.

<sup>23</sup> *Id.* at 9.

<sup>24</sup> *Id.*

be the utility's resource need)."<sup>25</sup> AWEC adds that even if we determine that IRP costs should not be considered in a cost cap investigation, "the IRP should have a role in at least providing a preliminary indication of whether a utility is likely to exceed the cap if it follows through on its action plan. Such a finding will put parties on notice that the cost cap may be exceeded based on the utility's actions, which will in turn create more certainty for parties when a cost cap investigation is initiated."<sup>26</sup>

CUB argues that section 10 provides that "a utility's *costs and investments incurred* to meet HB 2021's goals are subject to the bill's costs cap, as are also the *forecasted costs* estimated by the electric company for the purpose of compliance," adding that "[f]orecasted capital investments do not raise rates until they are used and useful, so it would be difficult to conclude that they have contributed to violating the six percent cost cap."<sup>27</sup> CUB points out that "IRPs are plans built on forecasted costs. IRP analyses do not provide anticipated rate impact of each investment. Rather, they compare net present value revenue requirement for the life of a project, but do not provide a year-by-year projection of 'rate impact.' This means that additional analysis is needed beyond what is supplied in an IRP for the purposes of HB 2021 compliance"<sup>28</sup> According to CUB, "[w]hile forecasted costs are uncertain, and arguably some are difficult to predict, the Commission already considers forecasted costs in its decision-making, and they are distinguishable from speculative future costs which are not included in rates. And the plain language of the statute shows the legislature intended forecasted costs to be considered in a Commission cost cap investigation."<sup>29</sup>

NWEC/RNW argue that the cost cap should apply "only to identifiable costs associated with utility investments capable of being recovered in rates via a general rate case or the application of Oregon's renewable automatic adjustment clause, not hypothetical costs projected earlier in the planning and procurement process."<sup>30</sup> NWEC/RNW add that "[i]n a standard general rate case, Oregon uses an embedded cost approach, meaning that utilities and regulators begin with historical costs and then *forecast* those costs into a future test year. A utility's actual costs may then fluctuate, but what the utility actually recovers in rates are those costs that were forecasted based on a historical test year and then carried forward to a future test year. \* \* \* Notably, speculative costs such as proxy

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<sup>25</sup> *Id.*

<sup>26</sup> AWEC Reply Br. at 9.

<sup>27</sup> CUB Opening Br. at 16 (emphasis in original).

<sup>28</sup> *Id.* at 18.

<sup>29</sup> *Id.* at 19; *see also id.* at 17 ("Oregon uses future test years for ratemaking. The Commission starts with historic costs, and then adjusts them for known and measurable changes, including forward-looking costs. Speculative future costs are not included in rates, but actual forecasted costs are").

<sup>30</sup> NWEC/RNW Opening Br. at 9.

resources identified to an IRP preferred portfolio and even shortlisted resources in an RFP are not forecasted into customer rates -- only actual, identifiable costs.”<sup>31</sup> NWEC/RNW note that “[n]ot only do IRPs bear no direct relationship to customer rates, but they are also based on broadly characterized needs to be met by proxy resources, which themselves may bear little relationship to the resources actually procured by a utility.”<sup>32</sup>

## 2. *Resolution*

The parties’ arguments demonstrate the tension embedded in this question. There is a desire for early information in order to manage cost impacts, holding them as close to the six percent cost cap as possible. Procedural, practical and statutory realities limit how early or how quickly we can actually implement a pause on compliance to address cost pressures and slow the pace of investments.

A pause in compliance obligations can only come at the end of a section 10 cost cap proceeding. It cannot be provided in the midst of an IRP proceeding, even if the lowest-cost resource portfolio that achieves compliance appears likely to breach the cost cap. As discussed above and highlighted by parties, the IRP and CEP can provide information – and create the crucial opportunity for insight into the emissions and cost associated with a counter-factual, non-compliant future – but the IRP and CEP processes cannot relieve a utility of its compliance obligation.

Pragmatic considerations lend additional support to our conclusion: At the IRP stage, the generic projections available to us are insufficient to support a cost cap determination. Similarly, while costs and resources at the RFP shortlist stage are known, though with some remaining uncertainty as projects may withdraw, the timing of the RFP process does not allow for a parallel section 10 proceeding. It would, moreover, be difficult, if not impossible, for a stakeholder to mount such a challenge to a shortlisted resource given the limited information available at the RFP shortlist stage.

Because years may elapse between a utility decision to commit to a project and when that project is recovered in rates, a narrow interpretation of “investments made, costs incurred or forecasted costs estimated by the electric company” that denied cost cap evaluation of investments until a project was used and useful would create a substantial lag in determining whether the cost cap has been breached and compliance should be paused.

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<sup>31</sup> *Id.* at 11.

<sup>32</sup> *Id.* at 11.

During that lag, the utility would be required to continue towards compliance, committing to yet more actions that may qualify for the rate impact analysis. Such a long delay in action on the cost cap seems to render the cost cap meaningless.

Thus, we will consider a utility commitment to a project as sufficient to meet the definition of “forecast costs,”<sup>33</sup> recognizing the imprecision of this approach. It may be that only the utilities themselves will have the information necessary to support a section 10 request before a rate filing has been made. If a utility believes that a cost or investment qualifies for the cost cap, we encourage it to make a section 10 filing promptly. Like any decision under section 10, a Commission determination that a future project to which a utility has committed qualifies for inclusion in the HB 2021 cost cap has no bearing on the prudence determination that we will make at the time the utility proposes to include the project in rates.

While we believe that this approach is the most feasible available to us within the constraints of ORS 469A.445, we recognize that it is an imperfect solution. Contrary to AWEC’s suggestion, it will not be possible for us to make a section 10 determination and exempt a utility from further compliance instantaneously, at the moment the utility’s costs exceed six percent of its annual revenue requirement; some amount of lag is unavoidable. For example, in the time between a utility’s signing of a contract that puts it over the cost cap threshold and our determination that the threshold has been met, the utility will be continuing to incur additional costs to carry out its statutory obligation to make continual progress toward HB 2021’s emissions reduction targets. To mitigate this timing issue to the extent possible under the statute, we reiterate that the utilities can and should submit section 10 filings when they have the information available to do so, and add moreover that each utility should monitor the cumulative incremental rate impacts of its existing *and planned* cost-cap-eligible costs and investments vis-à-vis its projected annual revenue requirements,<sup>34</sup> and notify the Commission and stakeholders if the utility believes it is approaching the six percent cap for a particular year, even if the actions at issue involve planned costs and investments that are not yet certain.

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<sup>33</sup> CUB’s dichotomy between “investments” and “costs” assumes that HB 2021’s use of the word “costs” is intended to be synonymous with the ratemaking sense of “expenses.” Both the dictionary definition and the Commission’s common use of “costs” are broader than CUB’s, and in particular, can include capital expenditures as well as expenses such as power purchase agreements.

<sup>34</sup> We recognize that the utility’s calculations will necessarily be somewhat speculative because it will be attempting to predict the Commission’s determinations with respect to cost cap eligibility of costs and investments as well as its future annual revenue requirements. These projections are not intended to bind the utility or the Commission in any way, but rather to provide advance warning to all affected entities that a utility may be approaching the cost cap.

Finally, we note that costs and investments that are not yet being recovered in rates must be compared against the projected total annual revenue requirement for the years in which they are expected to impact rates, not the utility's currently-effective revenue requirement. The development of such projections will be both fact-intensive and unavoidably imprecise.

### **C. Interaction between HB 2021 and RPS cost caps**

HB 2021, section 10 does not address interactions with the cost cap in Oregon's RPS law. How should the HB 2021 cost cap be applied to investments and costs required to satisfy the RPS?

#### **1. Positions of the Parties**

The Joint Utilities urge us to decline to issue any formal guidance on the question of interaction between the HB 2021 and RPS cost caps, and instead, allow for fact-specific resolution of this issue in future proceedings.<sup>35</sup> The Joint Utilities argue, in addition, that “[a] but-for test[] strikes too firm of a line.”<sup>36</sup>

AWEC argues that the HB 2021 cost cap should be applied to investments that are determined to contribute to compliance with HB 2021, regardless of whether those costs are associated with investments that also satisfy the RPS. They claim that it is reasonable to allow costs to count toward both the RPS cost cap and the HB 2021 cost cap because “the RPS and HB 2021 are intended to serve fundamentally different purposes. The Commission has already recognized that HB 2021 is an emissions-based law whereas the RPS is a requirement to acquire renewable resources.”<sup>37</sup>

CUB and NWEA/RNW support a but-for test, as described in Section II.A above: costs incurred for RPS compliance would count toward the RPS cost cap but not toward the HB 2021 cost cap.

#### **2. Resolution**

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<sup>35</sup> Joint Utilities Initial Br. at 7.

<sup>36</sup> Joint Utilities Reply Br. at 5.

<sup>37</sup> AWEC Opening Br. at 11. As noted in Section I.A above, AWEC argues at page 6 of its initial brief that costs incurred to comply with other statutes, including the RPS, can count toward the HB 2021 cost cap because “each of these separate legal mandates share a common purpose with HB 2021; that is, carbon emissions reduction.”

As stated in Section I.A above, a cost or investment is only included in the HB 2021 cost cap if compliance with sections 1 through 15 of HB 2021 is a major driver behind the action. It may frequently be the case, however, that a resource that is acquired for the purpose of HB 2021 compliance will also bring the opportunity to procure the renewable energy certificates (RECs) needed to contribute to the utility's compliance with the RPS. We have previously determined that HB 2021 is an emissions based standard<sup>38</sup> and thus many different technologies may provide the least-cost, least-risk path to achieving compliance with HB 2021's annual requirements. Some of those technologies will also support compliance with the RPS by producing RECs that the utility can procure and retire. As AWEC highlights, the RPS centers on RECs for compliance, utilizing inter-annual banking and the use of both bundled and unbundled RECs. The cost of RECs is clearly only applicable to the RPS cost cap and not the HB 2021 cost cap. The evaluation becomes yet more fact-specific and complex if the utility must procure an RPS-eligible resource that is more expensive than an alternative non-emitting resource in order to meet the bundled REC requirements of the RPS. If this limitation requires such a procurement, the incremental costs will be attributed to the RPS cap and not the HB 2021 cap.

#### **D. Time period for cost cap application**

Section 10 appears to contemplate that the Commission will forecast and then track the revenue requirement impact of all investments or costs determined to "contribute to compliance," authorizing a pause in utility compliance if their "actual or anticipated cumulative rate impact \* \* \* exceeds six percent of revenue requirement for a year." Is the statute clear that the cost cap applies only in individual years, based on the relevant costs experienced in a single year as a percentage of that same year's revenue requirement (i.e., without considering past or future years)?

##### ***1. Positions of the Parties***

Joint Utilities, CUB, and NWEA/RNW agree that the cost cap applies only in individual years. AWEC's interpretation is that "all costs that are determined to contribute to compliance would be forecasted out for the time period that the investment or cost would affect rates."<sup>39</sup> This exercise would include forecasting, for the depreciable life of the resource, the resource's cost, power cost impacts ("likely using forward prices assumed in the utility's IRP"), and tax impacts, as well as forecasting the utility's revenue

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<sup>38</sup> Order No. 24-002 at 5, 12-13.

<sup>39</sup> AWEC Opening Br. at 11 (internal citations and quotations omitted).

requirement “for as long as the costs that contribute to HB 2021 compliance are assumed to impact rates.”<sup>40</sup>

CUB notes HB 2021’s provision for future adjustments to the cumulative rate impact if the initial accounting was based upon the forecasted impact, raising the question of how often, and in what context, the Commission will update forecasted costs with the actual costs incurred. CUB suggests that the utilities be required to provide such updates in their annual CEP updates, in preference to holding a separate, time-consuming cost cap review proceeding.

Where an exemption has been granted, AWEC advocates for using general rate cases as the forum in which to evaluate whether the exemption should remain in force, arguing that (1) a general rate case is likely to materially impact the utility’s revenue requirement; (2) a general rate case will capture new cost-cap-eligible actions during the forecast period that were not accounted for in the original cost cap proceeding; (3) the depreciation of a resource is only updated in a general rate case; and (4) limiting reviews of cost cap exemptions to general rate cases would be less administratively burdensome than conducting annual reviews of in-force exemptions.

## 2. *Resolution*

We agree with commenters that the cost cap applies only in individual years, based on the relevant costs experienced in a single year as a percentage of that same year’s revenue requirement. As a practical matter, the costs that make up the annual revenue requirement can change substantially from year to year as power costs absorb fuel cost changes, short term contracts and resource variability such as low hydro forecasts. We expect that once a contested case proceeding has been initiated for a cost cap determination, that docket will remain open to facilitate monitoring over time. This approach will allow us to expedite the consideration of new evidence as it arises. We leave to further development how cost cap reporting, including updates to a utility’s projected revenue requirement for a particular year, should be made prior to a determination that the utility has reached the six percent limit for that year.

If, with respect to a given year, we have previously determined that the cost cap has not yet been met, we will consider evidence submitted to us in a section 10 request regarding the impact of any new or modified costs or investments impacting rates in that year, as well as any actual or proposed rate change, in ruling on whether an exemption is

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<sup>40</sup> *Id.* at 12.

warranted for that year. Once we have granted an exemption for a particular year, however, that year's exemption is not subject to later revocation based on new information. We do not interpret section 10 as contemplating revisiting exemptions granted pursuant to subsection (4), which will, as directed by the statute, be narrowly tailored and limited in duration. Additionally, an exemption from compliance that could be revoked at any time prior to, or even during, the year at issue would be no exemption at all.

We note for the sake of clarity that the cost cap does not permit an additional 6 percent rate increase every year; instead, for a given year, we are to consider the cumulative impact on that year's rates of all costs or investments that we have determined contribute to compliance with Sections 1 through 15 of HB 2021 as compared with the revenue requirement for that year.<sup>41</sup> To the extent they address the issue, the parties seem to share our interpretation of this requirement.<sup>42</sup>

Made, entered, and effective \_\_\_\_\_.

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**Letha Tawney**  
Commissioner

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**Les Perkins**  
Commissioner

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<sup>41</sup> See ORS 469A.445(3)(a) (“the commission \* \* \* shall: (a) Cumulatively calculate the rate impact caused by all investments or costs that have been the subject of a proceeding pursuant to this section, and must be included in calculation for the time period that the investment or cost would affect rates”); *id.* § 445(4).

<sup>42</sup> See, e.g., Joint Utilities Initial Br. at 9 (“if utilities were to procure several rate-based assets, and the cumulative costs from these resources was projected to exceed the cost cap throughout the depreciable lives of the assets \* \* \*, the Commission would be justified in allowing a continuing cost cap exemption for the depreciable lives of these resources (assuming that an annual cost cap compliance filing demonstrates that the relevant costs continue to exceed six percent of a utility’s then-current annual revenue requirement)”); CUB Initial Br. at 20 (“CUB believes the HB 2021 cost cap applies to the new costs associated with that single, specific year. The cumulative nature is that it includes that specific year’s rate impact caused by previous year’s investments if those investments contributed to compliance”).

## **HYPOTHETICAL SCENARIO**

UM 2273

### **Background and assumptions**

- 1) The applicable laws and regulations are those in place as of May 2025.
- 2) Except to the extent an exemption has been granted for a particular year pursuant to ORS 469A.445, the utility is subject to the requirements of ORS 469A.410(1) to reduce greenhouse gas emissions 80 percent below baseline emissions level by 2030, 90 percent below baseline emissions level by 2035, and 100 percent below baseline emissions level by 2040 and thereafter.
- 3) This hypothetical scenario takes place beginning in 2030.
- 4) Prior to 2030, the Commission found that certain costs and investments to which the utility had committed, but not yet placed in rates at the time of the Commission determination, contribute to HB 2021 compliance.
  - a) The Commission estimated:
    - i) The utility's total Annual Revenue Requirements (ARR) for 2030 and 2031; and
    - ii) Each project's annual impact on rates net of displaced costs.
  - b) On that basis, the Commission found that the HB 2021 costs and investments have a less than 6 percent impact on rates in 2030 and 2031. The Commission accordingly did not grant the utility an exemption from compliance for 2030 or 2031. The utility is required to reduce emissions to 80 percent below baseline emissions levels in both years.
  - c) The Commission declined to act on 2032 onward as that was deemed to be too speculative at the time of the decision.
  - d) The projects reviewed prior to 2030 attained commercial operation on January 1, 2030 and their costs are now being recovered in rates.
- 5) As simplifying assumptions, the following are not at issue:
  - a) Prudence of the utility's actions;

- b) Reliability-based exemptions pursuant to ORS 469A.440;
- c) Multi-state cost allocation.

### **Hypothetical Scenario**

#### **2030**

- 1) The Commission acknowledges the utility's 2029 IRP/CEP, which identified a need to procure the following to meet the utility's reliability needs, HB 2021 emissions reduction targets by 2035, other HB 2021 compliance obligations, and RPS compliance obligations:
  - a) A stated amount of non-emitting capacity and energy by 2035, including:
    - i) A stated amount of RECs sourced from ODOE-certified RPS-eligible renewable resources for each year from 2031 to 2035;
      - (1) The utility's RPS Implementation Plan included in its IRP states its estimated cost of meeting the annual RPS targets for each year from 2031 to 2035.
    - ii) A stated amount of energy efficiency;
    - iii) A stated amount of demand response;
    - iv) A stated amount of community-based renewable energy; and
    - v) A stated amount of small-scale renewable resources;
  - b) A stated amount of transmission capacity additions or upgrades by 2035; and
  - c) Retirement of a stated amount of gas capacity in 2035.
- 2) The "counterfactual" IRP portfolio submitted with the acknowledged IRP/CEP, which uses the same constraints and assumptions as the preferred portfolio, with the exception of those constraints and assumptions associated with compliance with sections 1 through 15 of HB 2021, includes:
  - a) Less non-emitting capacity and energy by 2035 than the preferred portfolio, including:

- i) A stated amount of RECs sourced from ODOE-certified RPS-eligible renewable resources for each year from 2031 to 2035;
  - ii) A stated amount of energy efficiency;
  - iii) A stated amount of demand response;
  - iv) A stated amount of community-based renewable energy; and
  - v) A stated amount of small-scale renewable resources;
- b) A stated amount of transmission capacity; and
  - c) Retention of the existing gas capacity which would be retired under the HB 2021 constraints in the preferred portfolio.
- 3) The utility submits, and the Commission approves, RFP design and scoring and modeling methodology consistent with the IRP/CEP modeling.
- a) The utility conducts an all source RFP for an amount of non-emitting capacity equivalent to 2/3 of the IRP need, COD by 2034. The utility states its intention to conduct a second RFP in 2031 for the remainder of its capacity and energy needs, including reaching the 90 percent reduction in emissions requirement, COD by 2035.
- 4) The utility identifies a least cost, least risk portfolio of projects that comprise the final short list. These projects satisfy two thirds of its full capacity and energy procurement needs identified in its IRP, and 100 percent of the capacity and energy procurement levels targeted in this RFP.
- a) The short list is comprised of 50 percent company owned and 50 percent PPA resources, consisting of batteries, wind, and solar.
  - b) 50 percent of each type of resource is COD by 2033; the other 50 percent is COD by 2034.
  - c) The utility provides the forecasted costs and benefits used in the RFP scoring and modeling.
  - d) The Commission acknowledges the final short list.

- 5) The company conducts contract negotiations, supervised by the IE, and finalizes pricing and all other contract terms for the final short list.
- 6) Once all contracts are signed, the utility makes an HB 2021 sec. 10 filing in which:
  - a) The utility argues that all of the projects qualify as contributing to compliance with sec. 1-15 of HB 2021;
  - b) The utility states that all projects will be eligible for inclusion in rates beginning in the years in which they attain commercial operation, with a projected gross impact on rates of:
    - i) In 2033, the ARR impact of the 2033 tranche of projects;
    - ii) In 2034, the ARR impact of the 2033 tranche of projects, accounting for depreciation, plus the ARR impact of the 2034 tranche of projects; and
    - iii) In 2035, the ARR impact of the 2033 and 2034 tranches of projects, accounting for depreciation;
  - c) The utility states that these amounts should be added to the already-recognized HB 2021 costs and investments, with updates to those preexisting costs based on the actual amounts being recovered in rates, for cumulative gross rate impacts stated separately for 2033, 2034, and 2035;
  - d) The utility states that the costs that the existing and new projects are displacing would have had a projected impact on rates stated separately for 2033, 2034, and 2035;
  - e) The utility projects its total ARRs separately for 2033, 2034, and 2035;
  - f) The utility separately states the resulting net cumulative impact on rates for 2033, 2034, and 2035, arguing the impact is greater than 6 percent of the ARR in each year; and
  - g) The utility requests an exemption from further compliance obligations for 2033 through 2035.

## 2031

- 1) The Commission agrees that all the new resources contribute to HB 2021 compliance and, after accounting for costs properly attributable to the RPS cost cap rather than the HB 2021 cost cap, finds a cumulative impact on rates of less than 6 percent in 2033 and over 6 percent in both 2034 and 2035, and accordingly grants an exemption from further compliance for 2034 and 2035.
- 2) In response, the utility announces its intention to delay retirement of its gas plant by one year (to 2036) and to reassess in 2032 the need for a second RFP for resources COD by 2036.
- 3) The utility submits its 2031 IRP.
  - a) The IRP identifies a need for:
    - i) A stated amount of new capacity by 2035; and
    - ii) A stated amount of new non-emitting capacity by 2036 to achieve the currently binding requirement to limit emissions to 90 percent below baseline once the utility is once again subject to HB 2021 compliance in 2036.
  - b) The utility's counterfactual portfolio selects new gas capacity in place of all new non-emitting capacity by 2036, with a Net Present Value Revenue Requirement (NPVRR) less than that of the preferred portfolio.
    - i) An intervenor submits evidence regarding decreasing non-emitting generation and storage costs compared to price volatility and fuel availability issues of natural gas, arguing that even in the absence of the requirements of sections 1-15 of HB 2021, new gas capacity would not be the least cost, least risk option.
- 4) The utility submits a GRC, on which the Commission acts by the end of 2031, resulting in a rate increase in 2032.
- 5) The utility submits its 2031 RPS update in which it indicates its cost of RPS compliance.

## 2032

- 1) An entity with section 10 filing rights asks the Commission to find that:

- a) Certain costs and investments included in the utility's most recent rate increase qualify for inclusion in the section 10 rate impact analysis;
  - b) Despite the overall increase in the utility's ARR, the utility's net section 10 compliance costs will continue to exceed 6 percent of the projected ARR for 2036 and 2037; and
  - c) Extending the exemption from the 90 percent reduction currently in effect for 2035 to each of those years is therefore warranted.
- 2) The utility submits its 2032 RPS update in which it indicates its cost of RPS compliance.

### **2033**

The company files a Renewable Resources Adjustment Clause request to recover the costs of all of the contracted resources from the 2030 RFP.

The utility submits its 2033 RPS update in which it indicates its cost of RPS compliance.