October 9, 2026
Public Utility Commission of Oregon
201 High St. SE, Suite 100
Salem, Oregon 97301-3398

RE: AR 676 Phase 2 - Track 1 Energy Advocate Response to Staff's V1 Electric Distribution Concept

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On behalf of Oregon Citizens' Utility Board, Oregon Just Transition Alliance, Green Energy Institute at Lewis & Clark Law School, NW Energy Coalition, Community Energy Project, and Multnomah County Office of Sustainability (collectively, the "Energy Advocates"), we represent a diverse group of environmental justice, climate, energy, and ratepayer advocacy organizations throughout Oregon. The following comments are in response to Staff's Track 1 Electric Distribution System V1 Concept.[1]

Staff's concept, as set forth in its September 25, 2026 filing, is generally strong, and offers useful clarifications and important considerations for moving forward both on electric distribution system capital, and on other decision points in other Phase 2 tracks. We look forward to future discussions in Track 2 and 4 on procedural design and appreciate that considerations are arising in Track 1 to inform that dedicated process. Understanding how what is being proposed will impact administrative burden for all involved, including whether existing processes (e.g. the DSP and IRP as currently designed) can support or new ones are needed, is also an important consideration. Zooming in and out on these processes as we move along is useful.

We understand Staff's concept to be clear that, especially for electric distribution capital, any instances for alternative recovery pathways should be rare. We especially appreciate Staff's assertion that just because a particular project is large, or the costs of a specific input increase faster than inflation, that does not mean that the indexed MRP is the wrong tool. Rather, the onus is on the utility to adjust and prioritize spending appropriately.

I. SCFM initial design considerations, including defining "project level materiality"

We are open to supporting limiting utilities to a maximum of 2 SCFM filings within an MRP term. Staff's SCFM concept also includes two tiers: 1) Tier 1 filings would be higher cost, policy-related investments (e.g. transmission, generation, storage, maybe IT projects with short lives), and it implies that it would be easier to get than a Tier 2 filing, which should rarely (if ever) be filed; 2) Tier 2 filings, would require a higher materiality showing and have more stringent expectations. We heard Staff also mention at the Electric Distribution stakeholder

[1] AR 676 - Staff Electric Distribution System Concept V1: https://edocs.puc.state.or.us/efdocs/HAH/ar676hah349606112.pdf ("Staff Concept")

discussion that the SCFM may be limited to only 1 use for distribution capital and thus SCFM tier 2.

We understand Staff's interest in adding this guardrail as a means to incentivize utilities to be sincere with its usage, but it can still be seen as an expectation for recovery–leading to utilities planning to use it twice per MRP term. We emphasize again that these are *limitations* and should not be seen as a pathway to routine outside cost recovery. Stakeholders should be on the lookout for utilities changing their planning processes in such a way that these alternative recovery pathways are seen as expectations. RMI has noted in its recent research on MRP pitfalls that capital funding mechanisms can create a "self-fulfilling prophecy" where the existence of the outside pathway enables "greater-than-needed spending."[2] Without limits, we will overwhelm the system and risk being worse off under this new framework.

We note that the Alberta jurisdiction uses a two-tiered approach where different "types" of capital have different thresholds and treatment. We understand that this has evolved over time from learnings that have taken place since 2013. For example, on average, 80% of utilities capex in 2017 came through capital trackers, and this outside-the-index approach resulted in a lot of administrative complexity leading to the erosion of MRP incentives, including concerns about information asymmetry.[3] The Alberta Commission made changes to thresholds and treatment, which also helped avoid frequent proceedings, and acknowledged that utilities could manage capex and not harm service quality. RMI summarizes the lessons learned in Alberta on supplemental capital funding mechanisms as follows: "It is vital to adhere to the core principles that the MRP is designed to support — cost control, cost efficiency, affordability, and risk sharing — when designing supplemental cost-recovery mechanisms."[4] RMI also recommends that any cost trackers associated with an SCFM be limited to prescribed cases and thus not be used to fund investments that would be made even if the tracker were not in place.[5]

As highlighted at least in the Alberta example, administrative burden for stakeholders will be greatly informed by the use of these alternative recovery pathways. Therefore, it is crucial that we can be as clear as possible about what is required from utilities at the outset for requesting outside recovery in order to ensure not only the burden of proof is on utilities, but that utilities have to come to the Commission having anticipated stakeholder inquiries into the request. Staff's concept of having a phased eligibility review process should consider this.

We strongly support Staff's interest in capturing how the SCFM reduces regulatory lag to the utilities. We would support a reduced ROE for SCFM capital to better balance risks and benefits

[2] RMI, Fixing Multiyear Rate Plans, January 2026: https://rmi.org/resources/fixing-multiyear-rate-plans/ at 18.
[3] *Id.* at 38.
[4] *Id.* at 40.
[5] *Id.* at 20.

between customers and utilities and would also support cost sharing and deadbands. We agree that this could work as a cost containment incentive and help interrupt utilities' capex bias (e.g. decision whether to file an SCFM or not would be impacted by the reality of a lower ROE). We also strongly support Staff's proposals around accumulated depreciation for costs recovered outside of the cap, the need for prudency review, and attention to ensure no double counting.

We also look forward to more discussion and legal analysis where needed on the interaction between SCFM and RAAC. However, generally speaking, we think it is worth considering that the circumstances under which the PUC determined the current implementation of the RAAC statute are not the same today. Using the RAAC as we do today in MRPs, in addition to an SCFM, is out of alignment with MRP principles of cost containment, efficiency, affordability and risk sharing. For that reason, we are eager to better understand how Staff sees the SCFM potentially meeting the statutory guidance in ORS 469A.120.

Lastly, we are interested in conversations around how the SCFM materiality thresholds and expectations may interplay with the opportunity for securitization per the FAIR Energy Act.

II. Z-factor limited to unforeseen eligible O&M and restoration costs

We agree with Staff that the Z-factor should be event driven, not project driven, for unforeseeable exogenous events and for distribution that is generally limited to restoration. This is a useful distinction, and is in alignment with best-practice literature on MRPs. In terms of Staff's thinking on Z-factor adjustments operating similarly to a deferral to amortization recovery path, we note our concerns about the historical deferral process not being robust enough and the first step often being skipped. Staff's noted enhanced guardrails and levers for risk distribution will be crucial, as will consistent enforcement.

We also appreciate the clarity Staff provided on how the Z-factor, SCFM, and a re-opener are different–and how re-openers are not for capital, but for correcting an underlying mechanism or assumption within the MRP. If a utility feels it requires additional revenue beyond what the index-based cap provides, this is not a problem with the plan itself and does not warrant a re-opener. We understand from MRP literature that reopeners are resource intensive and should be avoided as much as possible.

III. Eligibility criteria (incrementality, demonstration of alternatives, materiality, deadbands, sharing, etc.)

Generally speaking, eligibility thresholds for the Z-factor and SCFM should not be limited to a single metric, for example, an absolute dollar threshold. There should be multiple boxes that the utility should have to check for an alternative pathway to be warranted. We are interested in a

combined test approach. We also have concerns about eligibility determinations at the portfolio level rather than the project level.

IV. Alignment with Distribution System Planning (DSP)

We agree with Staff that ensuring the MRP and DSP can align is important, but think that the DSP needs to change to better serve needs related to setting going-in rates and understanding possible mid-cycle adjustments should they be allowed. Currently, we have found that DSPs tend to show what a utility wants to spend, but do not give us good enough information related to prudence. We need clear justification for why investments need to be made, especially related to questions of timing–answering "why now".

For example, PGE's meter replacement program opts to replace all meters at once, as it is cheaper than doing one at a time. But justification for why they need to be replaced right now is important. Where is the evidence that spending is necessary at this time? The DSP should provide metrics that answer these sorts of questions. For instance, in the case of meter replacement, what is the failure rate of the meters? Is it increasing? This type of information is also relevant to possible proposals for mid-cycle adjustments. Perhaps the DSP could require something similar to exhibit 401 in UE 473, PGE's current GRC, which includes project justification for all projects PGE is proposing recovery for. This type of filing can be a good starting point for questioning around prudency. Additionally, asking ourselves what might need to be included in the DSP related to potential future SCFM requests is worth exploring here as well.

Something else to consider is that the DSP is more than just distribution rate base and includes a large amount of transmission, generation, and other general costs. In terms of setting going-in rates, we should be thoughtful to create a process that protects against double counting a transmission substation, for example.

We can support normalization for recurring and volatile storm restoration costs. We are interested in exploring some sort of design within the normalization mechanism to limit overrecovery.

V. Updated depreciation and other associated revenue requirement adjustments for mid-cycle offsets

We strongly support Staff's thinking around updated depreciation. At the October 7 workshop, Staff gave an example of updating depreciation from a recent PGE rate case where depreciation for PGE's fleet of batteries was updated from its last GRC in response to the cost recovery for a battery project. This is an example of the minimum amount of depreciation that should be

updated and we encourage Staff to think about broader updates for equitable treatment related to regulatory lag.

VI. Early eligibility review process

Advocates support setting out a process through which the Commission can phase its review of a utility's request to use any of these exceptions, but with the assumption that stakeholders are afforded a fair opportunity and timeline to weigh in on the front end. As Staff makes clear in its initial concept, while these tools should be rarely used, it may be attractive to utilities to test the applicability of a Z-factor or SCFM to their O&M or capital investments if it means they can recover for those investments outside of the MRP. Aside from clearly defining the appropriate circumstances warranting use of these tools, a process that could allow the Commission to confirm whether the particular investment is eligible could save time and resources by all affected stakeholders, and even ideally afford more transparency into the request. This will likely require a lot of information sharing on the front end by utilities. Thus, trying to be as clear and thorough as possible in terms of requirements for what a utility needs to show, and what questions it needs to answer for such a decision, will be important.

One caveat to our thinking at this stage is that we would not want to replicate what we have seen with deferrals, which is also supposed to be a two stage process. The first step of determining whether the deferral is even allowed has at times been minimized or skipped, with concerns being handled at the second phase of amortization. Consistency, clear expectations for process, and enforcement will be important if Staff is considering such a phased approach.

Respectfully submitted this 9th day of October 2026,

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