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June 3, 2026

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street S.E., Suite 100
P.O. Box 1088
Salem, OR 97308-1088

RE: AR 676 –Portland General Electric Company Comments on Staff Straw Proposal

Dear Filing Center:

Portland General Electric Company (PGE or Company) appreciates the opportunity to comment on the Oregon Public Utility Commission (OPUC) Staff's straw proposal on the structure and design elements of a Multiyear Rate Plan (MRP) framework. Staff's straw proposal serves as a thorough starting point for the launch of Phase 2. PGE looks forward to working with Staff and stakeholders to refine, clarify, and provide additional analysis to shape the future of MRPs and deliver on the vision of HB 3179.

PGE remains concerned about the compressed development timeline. The rushed timing may prevent the Commission from striking a reasonable balance among Oregon's numerous competing statutory and operational priorities. While Oregon's MRP framework must be operationally robust, the rapid development and deployment necessitates a high degree of administrative flexibility in this first round of rules. National benchmarks indicate that a typical, reasonable timeframe for establishing such complex proceedings spans 18 to 30 months. The necessity for administrative flexibility in Oregon is further heightened by the unique scope of decisions contemplated for this venue. Unlike jurisdictions with a single monolithic utility such as Hawaii, Oregon features a diverse regulatory landscape with utilities operating under substantially different operational and geographic constraints. Crucially, unlike many jurisdictions where MRPs are established, Oregon does not operate within a full centralized wholesale market, nor are the utilities in those external jurisdictions typically vertically integrated. In many US jurisdictions operating under an MRP, utilities function as subsidiaries of a larger holding companies where generation and transmission assets are held at the parent level. Consequently, the costs subject to the MRP are largely limited to retail operations and localized distribution capital investment, while generation and transmission costs flow through to retail. Accordingly, the rules must allow Oregon utilities the administrative latitude to utilize a broader array of multi-year planning tools tailored to their specific circumstances within the boundaries of current statute.

Addressing Procedural Ambiguity

The procedural posture of this docket is unclear. Following initial discussion in December 2025, substantive workshops comments in January 2026, focusing on foundational education regarding MRP models, design elements and performance-based ratemaking.[1] In June 2026, prior to the publication of any draft rule text or the alignment of stakeholder positions, Staff intends to present its Phase 1 Straw Proposal to the Commission for final approval. This rapid transition from high-level education workshops to binding policy determinations creates structural ambiguity regarding how stakeholder feedback will shape the actual text of the rules moving forward.

The accelerated timeline in this docket departs significantly from the deliberative processes utilized in similarly complex, high-consequence rulemakings. For example, in Docket AR 638 (establishing the Commission's wildfire mitigation framework), the informal rulemaking phase extended over a full year before initial draft rules were issued.[2] The Commission then provided an additional six month period for workshops and iterative comments before initiating the formal rulemaking process.[3] Even after formal initiation, sequential rules phases and extended comment periods occurred over the cumulative 28-Month period to ensure an operationally viable framework.[4]

Docket AR 638 serves as a highly relevant benchmark because like Docket AR 676 it required the implementation of an entirely new regulatory paradigm driven by legislative mandates. The deliberate pace of AR 638 was not a function of administrative delay, but a structural necessity to ensure that diverse operational impacts were technically vetted and that stakeholder input was meaningfully incorporated into the final rules.

In contrast to past benchmarks, Staff's current trajectory in Docket AR 676 limits the opportunity for critical stakeholder input by compressing the evaluation of foundational policy shifts. The upcoming June public meeting appears structured to secure determination that could prematurely foreclose advocacy on vital technical components within the Straw Proposal. Given that an MRP framework fundamentally alters rate regulation in Oregon, a more iterative process is required.

Currently, Staff's straw proposal makes significant policy recommendations that are beyond the scope of Phase 1. Phase 1 was framed to adopt "core foundations and concepts."[5] Staff's Straw proposal is significantly broader than adoption of core foundations and concepts, including proposing that the Commission adopt specific design elements such as limiting MRPs to be indexed based, specific indexes being included and omitted, the type of decoupling (revenue), and a specific duration of MRPs, among others.[6] The codification of these specific design elements in administrative rule if not mandated by ORS 757.217. The Commission possesses the flexibility to

[1] *See e.g*, *Informal Phase: Staff Scoping Survey Summary Results* (Dec. 12, 2025); *See generally* Staff Slides for Workshop *2* at 6 (Jan. 28, 2026).
[2] *Rulemaking Regarding Electric Utility Wildfire Mitigation Plan*, Dkt. AR 638, Order 20-272 (Aug. 26, 2020).
[3] Dkt. AR 638, Order 22-011 App. A at 16 (Jan. 20, 2022).
[4] *See e.g,* Dkt. AR 638, Memorandum (June 10, 2022) (discussing the need for further rulemaking after the Commission adopted the initial rulemaking); Dkt. AR 638, Ruling (Jul. 7, 2022) (extending the comment period for the further round of rulemaking); Dkt. AR 638, Order 22-335 (Sep. 8, 2022) (adopting the secondary group of rules); Dkt. AR 638 Order 22-494 (Dec. 28, 2022) (adopting even more rules).
[5] Staff Slides for Workshop 2 (Jan. 28, 2026).
[6] Staff Straw Proposal (May 20, 2026).

rely on existing procedural rules such as OAR 860-022-019 regarding general rate case filing requirements to satisfy the statutory content requirement content mandates of ORS 757.217(2)(b)(A) without prematurely locking in rigid, untested structural elements.

Because these proceedings are in an informal phase, Commission determinations are not legally confined to a strictly developed evidentiary record.[7] This informality underscores the need for cautious deliberation. Staff and stakeholders are currently proposing far reaching changes to Oregon's ratemaking paradigm without the benefit of a detailed review of facts, data, or operational evidence that apply to Oregon utilities. Staff has not clarified whether a positive Phase 1 determination by the Commission will preclude subsequent evaluation of these core topics, nor has it outlined the mechanism by which these narrative proposals will be translated into formal rule language.

Furthermore, the Staff Straw Proposal does not reconcile its specific recommendations with boundaries of delegated legislative authority. It remains legally ambiguous whether the granular restrictions regarding indexing factors align with the explicit legislative directive regarding what administrative rules must contain under ORS 757.217(2)(b) or what they may contain under ORS 757.217(2)(c).

These procedural ambiguities stem, in part, from a departure from the Commission Internal Operating Guidelines.[8] Under established guidelines, the informal phased of a rulemaking utilizes workshops specifically designed to "review and seek comment on draft rule materials."[9] To date, no draft rule language has been produced for stakeholder evaluation.

Additionally, the guidelines dictate that the informal phased "ends when consensus is achieved or when it is clear that the positions of the participants are not likely to change with further discussion." Submitting the Staff Proposal for a definitive Commission decision at this juncture circumvents this core benchmark, as there have been not technical workshops, or collaborative adjustments to the proposal since its publication.

To remedy these procedural defects and ensure the development of a durable, legally resilient regulatory record, PGE respectfully requests that the Commission:

(1) **Clarify the precise scope** of each rulemaking phase, this request is made in light of the extensive design elements introduced in Phase 1 Straw Proposal;

(2) **Define the precise regulatory effect** of the Commission's decision approving Staff's Phase 1 proposal on subsequent phases;

(3) **Identify the specific statutory authority** the Commission relies upon to codify the specific details (e.g. specific indexing factors, TotEx, and decoupling) contained in Staff's Straw Proposal into administrative law; and

(4) **Defer a definitive Commission decision** until draft rule language is published and stakeholders are afforded adequate workshops to review, refine and develop the text.

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[7] *Int'l Council of Shopping Centers v. Or. Env't Quality Comm'n*, 27 Or. App. 321, 326 (1976).
[8] *Pub. Util. Comm'n of Or. Amending Internal Operating Guidelines,* Order 20-386 App. A at 9-10 (Oct. 7, 2020).
[9] *Id.*

PGE's Themes in AR 676

Notwithstanding PGE's above procedural requests, PGE provides the below comments that respond to the substantive proposals in Staff's Straw Proposal.

Three themes have been underlying PGE comments throughout this rulemaking:

- Flexibility
- Due process
- Clarity of direction

PGE is not alone in recognizing the need for flexibility. In Maine's MRP proceeding, the Maine Public Utilities Commission (MPUC) issued non-binding guidance on their preferred MRP framework in order to streamline rate cases, and proposed that MRP specifics around issues such as term of the rate plan, earnings sharing mechanisms, "off ramps", storm costs and PIMs are best addressed in rate cases.[10] PGE argues MRP regulatory structure where specific rate issues are addressed in rate cases rather that codified in administrative rules is best. Centering on a non-prescriptive, adaptive framework positions Oregon to have a more durable MRP framework.

This flexibility goes hand-in-hand with seeking to preserve due process. PGE encourages an MRP framework that defines necessary guardrails while leaving detailed methodologies to be developed through evidence in individual utility-specific proceedings informed by implementation. We appreciate Staff seeking to establish a framework with "targeted flexibility"[11] that facilitates what high performance means to individual utilities and the nimbleness to react to evolving state and community goals. We encourage a framework, particularly in Phase 1, that isn't too restrictive to react to the varied operational realities of Oregon's diverse entities and the changing conditions in which they operate over time.

In both the recent AR 677 Staff memo and in Staff's Straw Proposal acknowledge that stakeholders cannot align on a uniform scope of decisions. This divergence stems not from stakeholders intractability, but from distinct operational realities, geographic circumstance and regulatory positions of each utility. Rather than sacrificing utility stability and appropriate performance incentives for the sake of administrative standardization the Commission should use the contested case process to define key MRP parameters. Regulatory flexibility regarding these structural elements remains essential to the program's long-term success. At this stage, allowing utilities and stakeholders the latitude to propose a broader array of MRP constructs within individual rate cases is the most pragmatic approach. Consequently any guardrails developed within the AR 676 timeframe must be narrower than those outlined in Staff's current proposal.

Finally, PGE's comments throughout AR 676 have sought clarity of direction from the Commission. Taking a step back, MRPs function as tool under the broad umbrella of performance-based regulations (PBRs). They can be applied as high-level concepts and do not require highly specific constructs and consistency between all utilities in a jurisdiction. The Commission affirming exactly what it hopes to achieve through MRP is a helpful first step.

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[10] For example see the Maine Public Utility Commission, *Performance-Based Regulation Report with Recommendations*, page 91, June 27, 2025.
[11] *Id.* 3.

PGE finds it helpful that SB 688 detailed what is in the public interest for PBRs and Staff has taken the time to delineate principles, goals, and outcomes as part of the MRP process. In this regard all stakeholders would benefit from the Commission clearly stating their MRP objectives, goals, and desired outcomes early in the AR 676 Phase II process.

PGE's Comments on MRP Elements Detailed in the Straw Proposal

PGE appreciates Staff's articulation of key MRP design elements, how Staff's plans for these elements to work together, and the associated implementation processes. PGE is mostly aligned with Staff on the elements from the Straw Proposal. The Company's comments below are focused on those areas where PGE is (a) not fully aligned, (b) uncertain of Staff's direction, or (c) would like to influence the direction of the Phase II discussion on that element.

MRP Type: Index-based, Revenue Cap

While PGE is presently inclined toward use of an index-based MRP framework, utilities face diverse operational realities. The MRP rules should therefore provide utilities with flexibility to propose a forecasted approach when supported by an evidentiary record.

Staff's focus on a revenue cap overlooks how other MRP design elements contain costs and mitigate throughput incentives. In the Straw Proposal, Staff recommends a single regulatory archetype, intending to "Utilize indexing to inform the revenue cap over the plan duration and design the mechanisms in Phase 2 based on Staff's considerations."[12] This framework assumes that an index-based revenue cap is an inherently objective and superior mechanism for managing utility revenue requirements. PGE recommends preserving a utility's flexibility to propose alternative or blended multi-year structures—such as forecasted test-year tracks—when justified by a contested case record.

While Staff positions index-based rate adjustments as objective reflections of market realities, operational experience across the industry shows that these factors often involve regulatory policy choices. In practice, regulators and stakeholders utilize key adjustment factors, specifically the Productivity Factor (X) and the Stretch Factor (S), as policy levers to achieve specific administrative outcomes rather than relying solely on neutral economic data. Precedents from other jurisdictions demonstrate that commissions frequently separate metrics from objective industry-wide metrics:

- **Hawaii:** In its landmark PBR Decision and Order No. 37507, the Hawaii Public Utilities Commission (HPUC) set its productivity factor (X) at 0% for the initial regulatory period. This decision represented a deliberate policy choice to ensure baseline utility financial stability during the transition away from traditional ratemaking.

- **Alberta:** Under the Alberta Utilities Commission's (AUC) PBR framework, the commission historically adjusted the "X-Factor" based on regulatory policy judgments regarding consumer dividends and stretch expectations, rather than independent third-party Total Factor Productivity (TFP) metrics. This underscores that index adjustments often serves as administrative policy targets rather than mathematical equations based on economic trends.

[12] AR 676, Staff Straw Proposal, 1 (May 20, 2026).

Furthermore, the current record lacks empirical data or historical evidence demonstrating that index-based revenue caps outperform price caps or forecasted multi-year rate plans at containing costs or eliminating the throughput incentive. For instance, Maryland difficulties with achieving cost containment through the MRP has less to do with the forecast approach, than framework design decisions around annual reconciliation.[13]

National data compiled by the Edison Electric Institute (EEI) and the Brattle Group shows that the multi-year "stay-out" periods and the balancing mechanics of an Earnings Sharing Mechanism (ESM) drive cost containment, not the specific mathematical design of the cap. Similarly, independent revenue decoupling mechanisms, widely used in revenue-cap jurisdictions across the United States, effectively neutralize throughput incentives, proving that a revenue cap is not the exclusive path to achieve this policy objective. As such Staff should be focused on getting these large overarching design elements correct and allow utilities the flexibility to choose the MRP type that best balances the policy goals of the state with the needs of the utility.

Staff's proposed mechanism for manually updating load variables within the index formula diverges from national regulatory norms. The record does not support the assertion that annual forecast revisions improve administrative efficiency or accuracy; instead this requirement introduces regulatory uncertainty.

- **The Hawaii Alternative:** Hawaii's index-based revenue cap model, calculates allowed revenues via an the Annual Revenue Adjustment (ARA) formula based on a fixed, multi-year trajectory set at the beginning of the 5-year control period. The HPUC explicitly rejected annual load forecast true-ups within the base formula to preserve the cap's external incentive properties and minimize administrative burdens. Targeted reopeners provide a more predictive alternative to mandatory annual adjustments.

Integrating an annual load forecasting cycle into a multi-year framework may undercut the administrative efficiencies of an MRP and risks converting the process into an unpredictable rolling annual rate case. Utilities with rapidly evolving capital or "lumpy" capital needs benefit from customized MRP types, flexible adjustment factors, and regulatory certainty. [14]

PGE Position on Weather-Normalized Decoupling

PGE supports weather-normalized, decoupling based on use per customer. Because utilities face distinct operational realities, the regulatory framework should offer utilities the flexibility to tailor decoupling mechanisms to their unique circumstances. For PGE, partial decoupling approach best serves the system and its customer for four key reasons:

- **Targeted Customer Protections:** Restricting the mechanism to specific schedules provides greater rate certainty for the customer classes the FAIR Act sought to protect.

[13] Maryland Public Service Commission, Case No. 9618, *In the Matter of Alternative Rate Plans or Methodologies to Establish New Base Rates for An Electric or Gas Company*, Maryland's Office of People's Counsel, Sept. 16, 2024.
[14] *See* Maine Public Utility Commission, *Performance-Based Regulation Report with Recommendations*, page 69, June 27, 2025.

- **Balanced Incentives**: This structure enhances revenue stability while preserving incentivizes for efficient sales growth that outpaces costs, ultimately lowering the cost burden for all customers.
- **Regulatory Precedent**: To implement an equitable annual true-up mechanism PGE encourages OPUC Staff to review Hawaii's Revenue Balancing Account (RBA) established under HPUC Order No. 36326. This method provides a successful precedent for balancing utility stability with robust consumer protections.
- **Administrative Efficiency:** Re-establishing PGE's former decoupling framework avoids unnecessary administrative burden by leveraging tariff language and associated processes are already established.

PGE Position on Multi-Year Rate Plan Duration

Because each utility faces unique operating conditions, PGE advocates for a flexible Multi-Year Rate Plan (MRP) duration proposed by utilities in individual rate cases of between 3 and 7 years rather than a uniform five-year mandate. The governing statue explicitly requires a filing interval of no less than three and no more than seven years. Prescribing a single five-year term for all utilities predetermines an outcome for every circumstance and effectively reads this statutory range out of the law. The rules should instead permit utilities to propose an appropriate term within the three-to-seven-year range, subject to stakeholder comment and Commission approval within individual dockets.

This case-by-case approach reflects how multi-year plans function in practice. Utilities operate under materially different capital plans, planning cycles and operational needs. A utility with a stable near-term outlook may reasonably support a longer plan, while a utility facing major rapidly changing load, policy, technological, and economic conditions requires shorter duration. A flexible rule allows parties to evaluate the merits of a proposed term through testimony, pursue settlements, and enable the Commission to determine the optimal length on the specific evidentiary record of that proceeding.

Furthermore, Oregon's investor-owned utilities can manageably pace their filings within this statutory window without creating administrative strain. Even if all utilities maximize their schedules the Commission would review no more than two MRP filings annually.

Statutory and National Precedents

The current record lacks empirical evidence, economic analysis, or regulatory or legal precedence demonstrating that a 5-year term yields superior outcomes. Mandating a static timeframe diverges the explicit statutory language of ORS 757.217, which recognizes that utility circumstances require tailored regulatory approach. The Washington Utilities and Transportation Commission (WUTC) uses a flexible 2-to-4-year framework, enabling utilities to align their rate plans with specific multi-year procurement and capital cycles.

- **Hawaii:** The Hawai‘i Public Utilities Commission (HPUC) has served as a counter-example to a more flexible duration framework. However, this example is an anomaly due to the fact that HPUC is essentially regulating just a single regulated electric utility in the HECO Companies. HPUC was able to establish a 5-year target duration of the plan, with sufficient flexibility for re-openers and duration extensions on a case-by-case basis. It was

> able to establish this specificity of duration and many other constructs because they were developed for the purposes of a single operating utility.

A rigid 5-year standard overlooks the distinct service territories, resource requirements, and load trajectories of individual Oregon utilities. For example, PGE currently favors an initial 3-year duration for its inaugural plan. A shorter first cycle minimizes risk for ratepayers and the utility while all parties gain operational experience with the new regulatory framework.

Implementing a "Good Cause" Extension Mechanism

To ensure orderly administration, the rules should also permit a utility, upon a showing of good cause, to request a one-year extension of its filing for its next MRP. This mechanism directly aligns with the statute's express authorization for exceptions to rule requirements based on a showing of good cause.

This approach reflects successful regulatory models in other jurisdictions. For example the California Public Utilities Commission (CPUC) routinely grants filing extensions within its multi-year rate case cycles. In practice, several operational realities may justify a limited extension:

- Aligning the next MRP filing with a pending depreciation study;
- Accounting for the exact in-service timing of a significant capital addition; or
- Avoiding overlapping filings during periods of unusually heavy regulatory workloads for the Commission and stakeholders.

Allowing this targeted flexibility protects the administrative integrity of the framework and supports orderly scheduling without undermining the statutory requirements that utilities file multi-year rate plans on a regular interval.

MRP Scope and Capital Funding

Treatment

Staff's proposal consolidates a majority of utility costs into a single indexing baseline. PGE is in alignment with much of Staff's proposed "in-scope" and "recovered separately" inclusions on page 6 of the Straw Proposal but would like to clarify additional mechanisms and treatment of certain types of difficult to foresee and uncontrollable costs. Certain trackers and deferrals should exist outside of the scope of the multi-year indexed cap. PGE maintains Oregon's existing Renewable Automatic Adjustment Clause (RAAC) should stay outside the MRP framework. The RAAC serves as a proven, vital regulatory mechanism that enables Oregon's investor-owned utilities to recover the prudently incurred costs of constructing or acquiring renewable generation facilities and associated transmission lines on a timely basis.

Consolidating all capital investments into a rigid index baseline diverges from established regulatory practices and introduces avoidable rate volatility across MRP filings. As Brattle Group observes:

"supplemental cost recovery tools... are necessary to mitigate risks associated with major capital programs or areas in which cost increases cannot reliably be foreseen and/or are not controllable by the utility."[15]

Exclusion of Exogenous State Policy Mandates
Beyond the RAAC, the Commission should exclude exogenous, state-driven policy mandates from the scope of an index-based MRP. To maintain structural integrity and predictability, the rules should separate the following programs from the baseline index:

- The Community Solar Program: State-mandated procurement targets and program administration.
- Income Qualified Bill Discount Program: Evolving funding requirements by customer adoption and eligibility rates and shifting socio-economic demographics.
- Public Utility Regulatory Policies Act (PURPA) Qualifying Facility (QF) Contracts: Mandatory regulatory contracts executed to fulfill state small-scale renewable mandates.
- The power cost recovery framework including forecast costs (AUT) and review of historical variances of costs (PCAM). The key drivers of power costs include exogenous factors such wind, water, and solar conditions, loads, and wholesale gas and electric markets.

Incorporating these volatile, non-controllable policy costs into a standard historical index compromises the financial integrity of the multi-year plan and exposes customers to the need for re-openers. Conversely, maintaining separate, dedicated tracking mechanisms preserves financial integrity and ensures long-term transparency for all stakeholders regarding the direct impacts of state policy.

National practices in successful MRP states support separating policy-driven or non-discretionary costs from base revenue caps. The CEG report and Virginia Energy studies note that states facing complex policy environments utilize dedicated trackers such as New Jersey's Capital Adjustment Charge or Pennsylvania's Distribution System Improvement Charge to isolate exogenous costs from base revenue constraints.[16] [17]

Before moving on to Phase 2 PGE requests the Commission clarify how these rules will preserve the RAAC and exclude non-controllable state mandates from the baseline index.

Adjustment Factors

As discussed above, PGE believes determination of multi-year adjustment factors should be left for individual rate cases and allow for a variety of archetypes. The adjustment factors relevant in an individual rate case are dependent on the type of test year(s), the length of the plan, and other situational factors. Relevant adjustment factors, and in particular, the specific indexes and values used for applying them, may not be consistent between utilities and over time between cases. When an indexed-based cap is utilized, Staff's adjustment mechanisms as proposed may be

[15] The Brattle Group, *Performance Based Regulation Plans - Goals, Incentives and Alignment: Case Studies and Principles*, Research Report Archive (2024).
[16] Current Energy Group (CEG), *Multi-Year Rate Plan (MRP) Design Options Report for the Oregon Public Utility Commission*, Docket No. AR 676 (December 11, 2025).
[17] Virginia Department of Energy, *Examples & Lessons Learned from PBR in Practice: Multi-Year Rate Plan Design Considerations*, Policy Archive Report.

relevant, while if a long-term forecasted plan was needed, or most beneficial to ratepayers, many of these adjustment factors would not apply. PGE would likes the flexibility to propose forecasted plans, but will provide comment on each of the factors from Staff's straw proposal:

- **(I) = Inflation factors** are commonly utilized in indexed formula cap plans, often applied as an adjustment to total revenue requirement, but also as a targeted project tracker applied to a subset of revenue. The use of inflation factors, and particularly the index chosen to reconcile to, is dependent on the unique economic pressures on the utility, its customers, and the indices themselves.
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  As Staff discussed in the straw proposal, commonly used indexes include Consumer Price Index (CPI), Gross Domestic Purchases Price Index (GDPPI), or an industry specific supply-side price index. These indexes also have population selection and geographical variations. Selection and application of the appropriate index should consider the utility, the service territory, and to what it is being applied. PGE feels it is important for the rules to allow utilities the flexibility to propose an inflation rate of their choosing in the first MRP.
    - E.g., GDPPPI vs. Weighted Average like Avista in WA or CMP in ME). PGE would note that Hawaii Electric Company's experience with its first MRP was that the inflation forecasted did ***not*** keep pace with actual inflation.[18] (Hawaii used a forecast of Gross Domestic Purchase Price Index or GDPPI.) As an example of how this simple aspect of an index can cause a deficiency in revenues, HECO has gone on to propose moving away from GDPPI to suggest using a blended inflationary adjustment (such as the employment cost index) to "more accurately capture the inflationary pressures related to labor."[19]

- X and S Factors = PGE would be open to including an X and/or S factor in combination with an indexed cap rate plan. Use of these types of factors should be based on a Total Factor Productivity Study (TFP) for a specific utility and for a specific period of time. While these factors are commonly associated with the concept of "performance-based" ratemaking that incentivizes cost control, X- and S-factors are not necessary. Setting these values at 0 results in the same cost efficiency pressure, all other earnings adjustments equal.

- (G) = Open to it but not necessary under a price capped approach.

- (Z) = Already several deferrals existing that cover effectively act like a Z-Factor. Request staff be clear about which of the current deferrals would roll into the Z-Factor

- (Supplemental Capital Tracker) = We appreciate Staff being open to including this, as it should ensure in future MRPs accomplish the UM 2377 policy of growth paying for growth. It also allows for certainty and transparency in future cost-recovery and smoothing rates to avoid shocks.

[18] Hawaii Public Utility Commission, Docket No. 2018-0088, Hawaiian Electric, Phase 5 Opening Briefs, pages 6-7, May 5, 2025.
[19] *Id.* 47.

Regulatory Framework Design and Incentives

Symmetric Earning Sharing Mechanisms

PGE finds that a symmetric Earnings Sharing Mechanism (ESM) will be a core structural element to a balanced and equitable Multi-Year Plan (MRP). Symmetrical mechanisms maintain a utility's financial health and preserve a fair opportunity to earn a authorized return, especially during periods of high macroeconomic volatility. It ensures that customer safeguards operate in tandem with a utility's opportunity to earn a reasonable return.

The regulatory literature strongly supports using balanced ESMs to stabilize a utility performance. As the Brattle Group notes: "symmetrical reward and penalty structures... create both an incentive for an IOU to achieve a performance target and a disincentive for the utility to fall below."[20]

Furthermore, the CEG report highlights that an ESM provides the foundational guardrail necessary to make a multi-year stay-out period acceptable to capital markets. Conversely, extreme deadbands or asymmetric downside-only mechanisms limit a fair earning opportunity under ORS 756.040 and risk raising the Company's cost of capital. In practice, a symmetric ESM complements revenue decoupling by protecting customers from over-collections and utilities from under-earnings during periods of high macroeconomic volatility.

Capex/Opex Equalization (ToTex)

Explore a "ToTex" framework in Phase 2 presents significant practical challenges. As Staff notes, ToTex departs from standard US GAAP accounting principles and traditional regulatory law.

Developing the extensive evidentiary record required to reconcile a ToTex approach with foundational regulatory principles such as "return on and return of" capital typically requires more than six months. Given the compressed timeline to complete formal rulemaking by the end of the year, all parties would benefit from focusing limited resources on fundamental framework designs rather than introducing novel accounting concepts. PGE recommends that ToTex be excluded from consideration given these constraints.

Performance Incentive Mechanisms (PIMs)

Staff's proposal for penalty-only, "backstop" PIMs (covering reliability, safety, customer service) and upside PIMs for going above and beyond in high impact policy and customer service areas aligns with precedent in other jurisdictions, such as New York. PGE appreciates the opportunity to explore and refine concepts in Phase II and suggests that, similar to precedent in New York and Maine, the output of that process is recommendations on PIM categories. Specific PIM metrics, targets and incentive levels should be proposed and evaluated in utility rate cases.

Oregon should consider following the data driven timelines established by other states like Washington. When the Washington Utilities and Transportation Commission implemented its MRP framework, it spent several years tracking, collecting data on, and refining performance metrics through multi-party dockets *before* assigning financial rewards or penalties into formal rules.

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[20] The Brattle Group, *Performance Based Regulation Plans - Goals, Incentives and Alignment: Case Studies and Principles*, Research Report Archive (2024).

Designing Outcome-Based Upside PIMs
Regarding additional or "upside" PIMs, the Commission should ensure that provided examples are not too narrow and do not inadvertently become an exclusive list for Phase 2. Other metrics with high societal benefits where Oregon utilities have key levers of control, such as Virtual Power Plant (VPP) programs, should also be considered. The rulemaking framework should explicitly allow utilities and stakeholders to propose alternative PIMs tailored to evolving system needs. This stage of rulemaking should establish general principles aligned with SB 688 categories within the locus of utility control. It should not constrain ratemaking to specific programs or technologies.

The Commission should first define the top-priority *outcomes* it seeks to incentivize. For example Washington's development of multiyear rate planning began with the development of performance standards. This Phase 1 lasted from October 2021 through to March 2023, with utilities being required to propose metrics in their first MRP filings. This was only the beginning as Washington's comprehensive reporting and PIM regulatory framework evolved over time.[21]

Recommended Principles for Oregon PIMs
To ensure orderly administration during the initial MRP cycles the Commission should limit formal rules to basic backstop metrics and establish a clear framework for future PIM proposals. PGE recommends incorporating the following four principles:

- **Statutory and Policy Alignment**: Any proposed PIMS must directly reflect the public interest categories as articulated by SB 688 or goals and outcomes officially adopted by the Commission.[22]
- **Controllability:** PIMs must be tied to outcomes within the direct operational control of the utility. They must be measurable and with a baseline of available data.
- **Flexibility:** By their nature, multi-year rate plans are longe-term. Performance incentives and penalties should strive to be durable by allowing flexibility to achieve higher level outcomes that constrain incentives to specific programs or technologies.
- **Demonstrated Precedent**: Oregon's PIMs should have a foundation of success in other places.

Conclusion

PGE appreciates the opportunity to submit these comments on Staff's Phase 1 Straw Proposal. While the Straw Proposal provides a comprehensive initial framework, PGE urges the Commission to adopt an iterative, text-based approach moving forward to ensure the long-term success and legal resilience of Oregon's Multi-Year Rate Plan paradigm.

To achieve a durable regulatory framework that balances the mandates of HB 2021, HB 3179 and SB 688 with grid reliability and customer affordability, the final rules must prioritize structural flexibility over administrative standardization. Oregon's unique, vertically integrated utility landscape demands a framework tailored to utility specific capital plans and distinct operational

[21] Most recently the WUTC, in Docket U-210590, issued an interim policy statement with guiding principles on PIM's in April 12, 2024, establishing an updated set of PIMs in August 2, 2024, conducted more workshops in the summer and winter of 2025, and then issued a final set of PIMs on January 26, 2026.
[22] See ORS 757.046(2) a - f

constraints. PGE looks forward to collaborating closely with Staff and stakeholders in Phase 2 to refine these rules, establish clear Commission objectives and build a technically vetted framework that leaves granular design methodologies to utility specific contested proceedings.

In summary, PGE respectfully requests that the Commission adopt the following path forward:

- Establish Procedural Clarity: Defer a definitive Phase 1 decision until initial draft rule language is published, allowing stakeholders to review and refine the text through collaborative workshops as prescribed by the Commission's Internal Operating Guidelines.
- Preserve Administrative Flexibility: Refrain from codifying rigid, one-size fits all design elements such as a mandatory five-year term or an exclusive index-based revenue cap and instead allow utilities the latitude to propose customized MRP structures (between 3 and 7 years) within individual rate cases.
- Protect Evidentiary Due Process: Utilizing individual contested cases proceedings, rather than sweeping administrative rules, to establish specific indexing values, productivity factors and Performance Incentive Mechanism (PIM) targets rooted in historical utility data.
- Insulate Core Capital Mechanisms: Explicitly exclude volatile, uncontrollable exogenous policy costs including the Renewable Automatic Adjustment Clause, power costs (AUT/PCAM), and state-mandated social programs from the baseline indexing cap to prevent structural revenue deficiencies and rate instability.
- Optimize Phase 2 Resources: Focus stakeholders efforts on fundamental framework architecture and proven billing adjusters by explicitly excluding complex, non-GAAP accounting paradigms such as TotEx from further evaluation.

Please direct questions to JP Batmale at jp.batmale@pgn.com and all formal correspondence and requests to pge.opuc.filings@pgn.com.

Sincerely,

\s\ *Jason Salmi Klotz*

Jason Salmi Klotz,
Senior Manager, Regulatory Strategy