Portland General Electric
121 SW Salmon Street • Portland, OR 97204
portlandgeneral.com

September 4, 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 – In the Matter of Rulemaking to Establish Multi-Year Rate Plan Framework, Portland General Electric Company, Track 1 Distribution (Capital) Cost Category Pre-Read

Dear Filing Center:

Portland General Electric (PGE) appreciates the opportunity to provide this Pre-Read regarding the treatment of electric utility distribution under Oregon's emerging Multi-Year Rate Plan (MRP) framework. As part of this rulemaking Staff has requested the electric utilities develop three pre-reads covering the following Track 1 Cost types:

- Operations & Maintenance (O&M)
- Distribution Capital
- Transmission Capital and Other Costs

PGE hopes to accomplish two things with our pre-reads. First, they should cover, at a minimum, the wide variety of topics and issues listed in Attachment 1 of Staff's Phase 2 Workplan.[1] Second, the pre-reads – and any subsequent discussion of them – should raise other issues that may need to be considered in Tracks two through four.[2] Accordingly, PGE has chosen to expand the focus of this pre-read from just distribution capital to cover all capital.

Part 1 - Foundational Information

What Is Capital as a Cost Category to a Utility?

Electric utilities are among the most capital-intensive businesses in the economy and are different from other industries as they are simultaneously capital intensive, low growth, and heavily regulated. Electric utility capital costs consist of long-lived utility assets used to safely and reliably deliver electricity from generation via the transmission and/or distribution systems to customers along with necessary services. Those capital assets are financed with debt and equity and then recovered gradually from customers through regulated rates Common examples of capital projects include, but are not limited to:

- High- to low- voltage transmission lines
- Utility-owned generation
- Substations and circuit breakers
- Distribution transformers
- Poles, overhead conductors, and underground cable

[1] AR 676, Rulemaking General Rate Revisions HB 3179, Staff Phase 2 Workplan, August 7, 2026, page 9.
[2] AR 676, Staff comment at O&M Workshop on August 26, 2026.

- Protection, control, and voltage-management equipment
- Grid-modernization technologies
- Metering infrastructure needed to connect new loads

Unlike O&M expense, capital investment creates an asset that remains in service and generate a return. The utility recovers the costs for capital expenses over the life of the equipment, while O&M expenses are generally recovered in the year they are incurred as a type of pass through. Once an asset is placed in service and approved for rate recovery, its cost is generally recovered over its useful life. This happens through two mechanisms: *return of* (depreciation) and a *return on* the undepreciated investment. These underlying concepts drive a large portion of the utility ratemaking and determine the financial health of most utilities.

Utilities invest in infrastructure to serve customers in exchange for an opportunity to earn a reasonable return on the investment. PGE's most recent general rate case (UE 473) shows an average rate base (i.e., capital accumulated over time) of roughly $8.6 billion. Accordingly, there are more regulatory structures and procedures built around the recovery of costs for capital as it drives utility profits and overall value.

Exploring the concept of "Return of, Return on" capital provides a good insight into how capital differs from O&M as a cost ***and*** why the utilities seek an understanding of and certainty around how MRP may impact cost recovery. For a capital cost, customers generally pay two components:

- Return ***of*** Capital – recovery of the original investment through depreciation
- Return ***on*** Capital – recovery of financing costs (debt & equity) through the authorized return applied to undepreciated rate base

In general rate cases, PGE's capital investments enter rates through the revenue requirement calculation. The calculation's variable *Depreciation* represents the "Return ***of*** Capital." The equation *(Rate Base x Allowed Return)* represents the utility's "Return ***on*** Capital."

$$Rev.\ Req. = Operating\ Expenses + Depreciation + Taxes + (Rate\ Base \times Allowed\ Return)$$

As an example, here's a simplified version of a UE 473 distribution project:[3]

- Distribution substation investment (including property tax) = $100M
- Depreciation life = 40 years
- Average rate base during Year 1 = $95M
- Authorized after-tax rate of return = 7.49%
- Using traditional cost-of-service ratemaking the "return of capital" would be $\$100M/40$ years for an annual depreciation expense of $2.5M.

The "return ***on*** capital" would be $\$95M \times 7.49\% \approx \$7.1M$. Ignoring taxes, these two costs together create an annual revenue requirement of $\$2.5M + \$7.1M \approx \$9.6M$ in a traditional rate case.

In simple terms, revenue requirement is the amount of annual revenue a utility must collect from customers to recover its prudently incurred capital costs and earn its Commission-authorized return.[4] The average rate base

[3] This example is highly simplified for illustrative purposes only. These project costs and their treatment are not an accurate reflection of how costs would appear in an actual PGE filing and lack such elements as Weighted Average Cost of Capital, or interest expense.

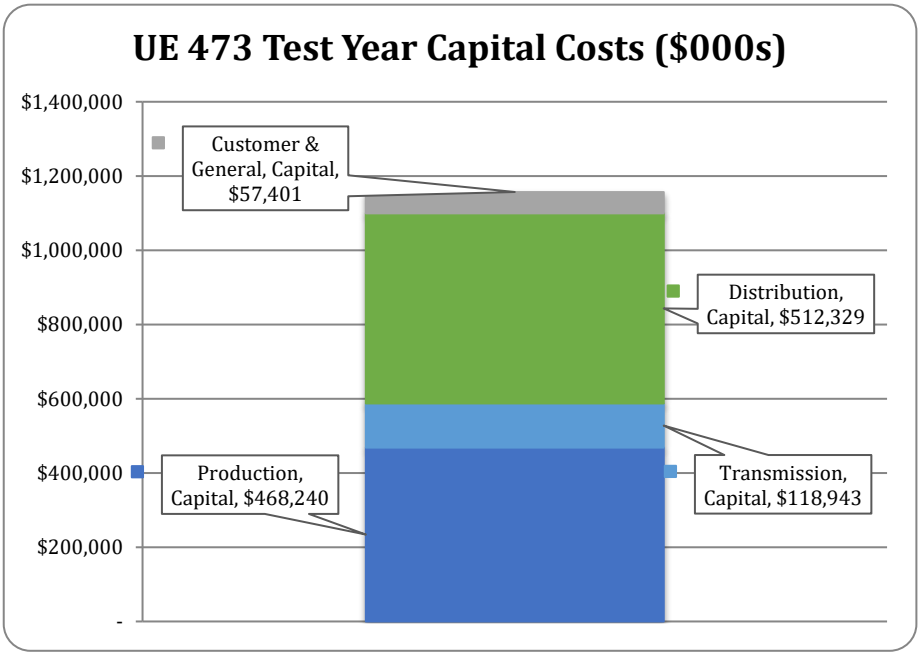
methodology under the current rate case framework links capital additions to revenue requirement remain. Oregon's MRP framework slightly alters that relationship to increase cost discipline and predictability. Utilities must seek to match investments to available revenues under the revenue cap or other tools like the Supplemental Capital Funding Mechanism (SCFM). For example, Hawaii's MRP includes an Exceptional Project Recovery Mechanism because its indexed plans cannot fully address large capital additions through the basic formula alone.

Accounting and the Design of Cost Recovery under MRP

The centrality of capital to the financial health of utilities means the design of an MRP impacts its ability to raise funds for investments. Generally accepted accounting principles (GAAP) require that a regulatory framework provides a reasonably clear relationship between costs and expected cost recovery.[5] This is not an argument that GAAP accounting should dictate outcomes in AR 676. The design and application of complementary mechanisms within the MRP Framework – like the SCFM, decoupling, Earning Sharing Mechanism, trackers, reopener, and rebasing process – can ensure alternative ratemaking does not threaten a utility's designation as a regulated operation. In short, the costs of capital investments deemed prudent just need to be recoverable. Clarity of treatment of regulatory assets combined, with MRP mechanisms that retain some link between approved costs and utility revenues, can create financial certainty while achieving cost containment.

Capital in Docket UE 473

UE 473 PGE proposed nearly $1.2 billion in capital costs. *(See the graphic below.)*



[4] The authorized return reflects the risk profile of a regulated utility. In capital markets, investors generally require higher returns when they bear greater uncertainty regarding cost recovery, revenues, competition, or asset utilization. Under the regulatory compact, utilities accept an obligation to serve and extensive regulatory oversight in exchange for a reasonable opportunity to recover prudent costs and earn an authorized return. This framework reduces certain business risks relative to many competitive industries, allowing utilities to attract capital at lower expected returns while providing customers with the benefits of lower financing costs. The result is a balance between investor and customer interests: sufficient opportunity to attract the capital needed to build and maintain essential infrastructure, while limiting customer costs through a lower risk, lower return model.

[5] See Financial Accounting Standards Board standards for regulated operations 980.

PGE actively manages and rebalances the portfolio of capital projects it forecasts and implements as circumstances evolve. This process would continue under the MRP. For example, the distribution plant (capital) in UE 473 illustrates PGE's planning. Going into the rate case PGE's distribution capital call began with 79 projects totaling approximately $2.736 billion (ideation = new projects). The portfolio was narrowed through governance stages to 25 projects totaling approximately $0.512 billion at the design-funding gate.

Governance stage	Projects	Estimated total cost (billions)
Ideation *(new projects)*	79	$2.736
Sponsorship	38	$1.136
Capital portfolio planning	28	$0.986
Design funding	25	$0.512

The progression shows how distribution capital projects were screened, sequenced, rescoped, or deferred as information improves and constraints change leading up to the rate case filing. The MRP's revenue cap will serve as another variable in PGE's capital selection process.

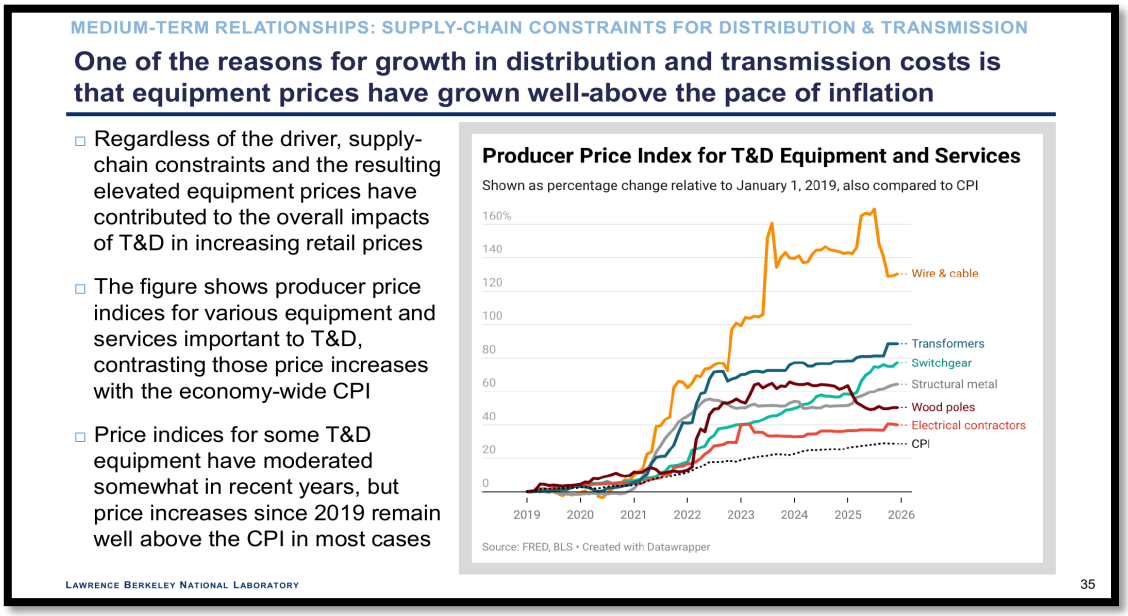
Drivers of Capital Costs

An electric utility's overall capital **needs** can be driven by a host of situations: customer growth, economic development, electrification, wildfire resilience, aging equipment, etc. The financial health of a utility depends not only on operational performance but also on the regulatory confidence that prudent capital investments will be recoverable through rates. As such, the financial health of an electric utility is inseparable from its ability to attract investment capital from the market at reasonable cost and recover prudent investment through rates. This cycle to attract market investment capital and recover a reasonable rate of return on that investment can lead to a capital investing bias; the MRP Framework seeks to address this bias.

External pressures also drive the **cost** of capital investments. The 2026 LBNL/Brattle retail-price update[6] notes that inflation on distribution capital spending has contributed to retail-price increases in some regions. The figure below illustrates a key challenge for an MRP index: since 2019, producer-price indices for several types of equipment and services important to transmission and distribution have risen faster than the economy-wide Consumer Price Index (CPI). The report states that while some equipment-price indices have moderated recently, most remain well above CPI growth.

[6] Wiser RH, Barbose GL, Gorman W, et al. *Retail Electricity Price Trends and Drivers: Data Update-2026 Edition*. Lawrence Berkeley National Laboratory; March 2026. Accessed September 2, 2026. Retrieved from https://emp.lbl.gov/sites/default/files/2026-03/Retail%20Price%20Trends_2026%20edition.pdf.

Figure 1. Producer price indices for T&D equipment and services compared with CPI[7]



External cost pressures that were not anticipated – like high inflation for distribution equipment – should **not** automatically flow through to customers through a deferral or balancing account. But, the MRP Framework should provide clarity around how the various elements must work in coordination to support necessary capital investments.

Examples of Capital and O&M Working Together

PGE understands that a well-designed MRP Framework should lead to synergies of better customer outcomes while lowering costs. In Docket UE 473, PGE identifies how it implemented targeted automation (capital - IT) and a streamlined application process (O&M – IT labor) to create operational changes that have cut interconnection processing times from 32 days in 2023 to three days for standard residential approvals in 2025. This allowed PGE to deal with a 23% increase in application volume without increasing headcount or employee hours, all whilst improving the positive customer experience to 70% of all interconnection customers by 2026.

Part 2 - Capital and MRP Elements

Per Staff's AR 676 Workplan, PGE addresses questions about the relationship of capital costs to MRP Elements.

Going-In Rates

PGE supports establishing the initial, capital-related revenue requirement through a traditional rate-case process. PGE believes an evidenced-based starting point matters because future MRP adjustments build from that base. Continuing to establish going-in rates in a Commission-reviewed cost of service process provides a clear foundation for cost recovery while maintaining incentives for cost containment.

Relationship to Planning Dockets

Capital investment can be informed by reporting and planning. These processes can also identify a future need for alternatives, however neither reporting nor planning necessarily *decide* cost recovery. The MRP or SCFM proceeding should address whether, when, and on what evidence an investment enters rates. As Oregon has

[7] Ibid, slide 35.

selected an index with revenue cap rather than a forecasting-based MRP, there should be limited need for a forecast of capital projects as part of the process to establish the revenue requirement beyond the test year.

Indexed Adjustments and Their Limitations

The MRP index with revenue cap should establish a baseline of revenue to handle broad annual changes in capital, with the SCFM and RAAC playing complementary roles for large, lumpy capital investments.

Tool	Primary role	Illustrative fit	Cadence
MRP index	Broad, formula-driven annual change	Routine investments reasonably covered by the formula	Every MRP
SCFM	Qualifying material capital additions	A material project or portfolio placed in service during the MRP	Ad hoc
Deferral or balancing account	Narrowly defined authorized cost	An eligible cost not captured elsewhere	Annually or leading into the next MRP period
Rebasing	Refresh the full revenue requirement	Update rate base and cost relationships for the next MRP	Leading into the next MRP period

Deferrals, Balancing Accounts, and PIMs

Under the proposed MRP framework, deferrals and balancing accounts should become more limited and targeted for capital recovery. Historically, deferrals and balancing accounts have been used to reconcile volatile or difficult-to-forecast costs and revenues outside of general rates. For capital investments that don't fit under the index, the first option should be exploring the use of the SCFM, if needed. Staff has expressed concerns that excessive use of trackers, deferrals, and balancing accounts could weaken the cost-management incentives that MRPs are intended to create. PGE agrees their use should be limited but there may be a need for trackers, deferrals, and balancing accounts for some capital costs in the future. To this end, their relationship to SCFM, exceptions, off-ramps, rebasing, and Z-factors needs to be made clear. If not, uncertainty will emerge around cost recovery harming both the utility and ratepayers.

Performance incentive measures (PIMs) should help to ensure that cost containment does not come at the expense of safety, reliability, or customer service but may force tradeoffs elsewhere. Penalties and incentives that align utility actions with customer outcomes will force the utility to balance cost-containment against the risk of poorly timed capital deployments.

Scenario

Oregon adopts a reliability PIM tied to outage duration in energy burdened neighborhoods. The PIM involves penalties. By Year 3 of the MRP PGE identifies several distribution feeders experiencing increasing equipment failures in two energy burdened neighborhoods.

PGE must assess the investment in new feeders relative to other capital needs, along with the risk of missing Oregon's new reliability target. This PIM strengthens the business case for accelerated replacement, if only to avoid penalties. However, the utility must also evaluate whether the investments can be accommodated within its MRP revenue cap or if other projects must be deferred and when all of these tradeoffs should occur. So, while the PIM creates an incentive to reduce reliability risk, the MRP Framework limits options to raise rates beyond the revenue cap and forces tradeoffs.

Regulatory Safeguards: Prudence and Used-and-useful

An MRP changes the timing and structure of rate review; it does not eliminate the Commission's traditional safeguards. Two key concepts to capital investment are prudence and the used-and-useful standard. While related, they ask different questions:

Concept	Plain-language question	Primary focus
Prudence	Was the decision reasonable when it was made?	The decision process, information available, alternatives, risk, cost, and response to changing facts.
Used-and-useful	Is the asset presently serving customers or providing a current system benefit?	The asset's in-service status, operational availability, function, and present utility benefit.

Prudence review focuses on whether a utility acted reasonably based on the information available when a decision was made. It does not require perfect forecasts or use hindsight to convert an unfavorable outcome into an imprudent decision. At the same time, prudence is not established merely because money was spent.

As part of the MRP Framework, PGE will be prepared to explain capital costs with information about need, alternatives, timing, variances, and how decisions changed when new information emerged, but questions the breadth and depth of info required on an annual basis. The annual MRP process needs to avoid becoming a mini-rate case. For projects that fall under the index, the prudency of investments should be evaluated at the end of the MRP period. PGE believes an annual attestation for what was put into service should suffice for administrative oversight during the MRP.

Used-and-useful review protects customers by linking rate recovery to the asset that provides utility service. Across capital categories, "useful" should recognize system functions. With regards to the capital under the Index or under the SCFM, PGE recommends a showing which addresses four practical questions:

- Is the asset complete and in service?
- Is the asset energized or otherwise operationally available for its intended function?
- What current customer or system benefit does it provide?
- Is the asset reasonably sized and timed given the information available and the utility need it was designed to address?

The last question overlaps with prudence, but the standards should remain distinct. An asset can be operational and useful even if parties dispute the cost or timing decision. Conversely, a prudently initiated project may not yet be used-and-useful if it remains unfinished or unavailable for service.

MRP Elements & Regulatory Lag on Capital

The combination of Year 1 "going-in" revenue requirement with annual adjustments through the (I-x)-S+G+Z index[8] can create a disconnect between when an asset cost is realized versus when the costs are recovered. This is called regulatory lag and it can strengthen incentives for cost control by shifting a portion of cost-recovery risk from customers to utility investors. The MPR will create regulatory lag because revenues will grow at the rate of the index formula, rather than actual changes in costs. Investors generally require higher returns for greater risk. To the extent the MRP framework can balance cost-containment objectives with clarity on cost recovery the MRP will create an environment that supports continued investment in essential utility infrastructure and avoiding upward pressure on financing costs.

The relevant policy question is therefore not *whether* regulatory lag should exist, but whether an updated framework appropriately distinguishes between ordinary business risk – which should remain with the utility – and material cost recovery risks associated with prudent investments which cannot reasonably be accommodated within the index.

Scenario

PGE chooses to prioritize an upgrade to a local distribution line to improve local system reliability and to meet local, forecasted load growth. During the project PGE experiences equipment cost overruns due to inflation and contractor productivity issues due to a labor shortage. How should these extenuating factors driving up the capital costs be treated?

While PGE made no mistakes in prioritizing the project or selecting the contractor, these types of cost overruns on routine distribution projects represent an ordinary business risk. Under the MRP, PGE's main option is to simply reallocate funds from another project and then defer that project. No permission or guidance would be needed from the OPUC. Seeking incremental recovery (e.g., tracker) could be an option, but PGE would need to show good cause as the MRP framework seeks to incent efficient execution and cost discipline against the total budget under the index.

A comparison between UE 473 and AR 676 highlights some key differences in cost recovery and the attendant risks:

UE 473 Cost of Service Ratemaking (COSR)	AR 676 Indexed Revenue Cap
Capital directly drives rates	Capital only indirectly influences rates
Average rate base updated in rate case	Revenue path predetermined by index
Revenue follows investment	Investment may occur before revenue adjustment

8

Regulatory lag varies by rate case filings	Intentional regulatory lag exists due to stay-out (Current proposed structure)
Capital reviewed comprehensively in GRC	Capital reviewed at the end of the MRP or through SCFM/rebasing/other mechanisms for eligible projects

Part 3 - Supplemental Capital Funding Mechanism

Staff positions the SCFM as a supporting mechanism to address material changes and qualifying capital investments over the plan period so as preserve the core discipline of a multi-year framework.[9] PGE agrees and sees the SCFM as an essential component of the MRP because the index formula alone cannot reasonably accommodate all capital investment needs over a five-year plan term. The MRP scope and capital funding are inseparable; experiences from other jurisdictions show that successful MRPs generally provide a mechanism to address select capital expenditures outside the core index.

Other Jurisdictions	Indexed/PBR Framework	Capital Recovery Mechanism
Hawaii	Revenue-cap PBR	**Exceptional Project Recovery Mechanism (EPRM)** for extraordinary capital projects.
Ontario	Incentive Regulation / Price-Cap IR	**Incremental Capital Module (ICM)** and other rate mechanisms for capital outside normal index adjustments.
Alberta	PBR framework	Extraordinary projects can receive separate treatment from capital addressed through the PBR framework.
Massachusetts	Alternative regulation with trackers	Capital trackers, K-bars, and project-specific recovery mechanisms are layered onto broader regulation.
Maine *(proposed)*	Index-based revenue cap	Commission materials specifically contemplate an "F-factor" supplemental funding mechanism with similarities to Hawaii's EPRM.

In each of these other jurisdictions, the SCFM-like mechanisms:

- Allows both project and portfolio pathways with a focused true-up
- Coordinates SCFM recovery with decoupling, the ESM, planning processes, and rebasing
- Preserves appropriate cost-allocation and rate-design review so approval of recovery does not predetermine who pays
- Leverages experience from Hawaii and other jurisdictions as evidence of workable design choices, while tailoring Oregon rules to Oregon law and circumstances
- Maintains a clear cost-based foundation and sufficiently definite Commission findings to support continued evaluation of regulated-operations accounting under GAAP

For sufficiently large investments, the Commission may also wish to consider whether securitization or other financing approaches could reduce customer costs, consistent with applicable statutes. While financing alternatives do not replace evaluation of project need, prudence, used-and-useful status, and eligibility for

[9] AR 676, Staff's Public Meeting Memo, page 11, June 16, 2026.

recovery, they may provide an additional tool to reduce customer impacts associated with large capital investments.

Guiding Design Principles

PGE recognizes that the SCFM design must avoid undermining MRP incentives around cost discipline and cost containment. The SCFM design should reflect:

- Targeted eligibility, not routine recovery of ordinary capital spending
- A clear materiality test based on a combination of revenue-requirement impact and agreed-upon principles
- Commission review of prudence, used-and-useful status, actual cost, offsets, and customer benefits
- No duplicate recovery through the index, another tracker, customer contributions, grants, or base rates
- A defined true-up and transition into base rates at rebasing
- Coordination with decoupling and the ESM so mechanisms measure the same authorized revenue and cost responsibility
- Be additional to the Renewable Automatic Adjustment Clause, which is established in law.

In terms of materiality, PGE recommends evaluating materiality using a revenue-requirement impact. Gross project cost alone may not be fair eligibility criteria, as customers pay the annual revenue requirement, not the construction cost in one year.

Scenario

A national cybersecurity event causes NERC to announce Year 3 of PGE's MRP requirements for new equipment. PGE must undertake an expensive IT capital upgrade beginning in Year 4 of the MRP that swaps out most of the communication hardware at all of PGE's substations and generation facilities. The average, all-in project cost is $500,000 per substation.

PGE has over 160 substations. It would be impractical to hire a single contractor to conduct the upgrades across all substations two years or less. If PGE were to split this work equally into 20 contracts, no single contract/project would be more than $4 million, but the portfolio's combined annual revenue requirement would be material. Should the SCFM be allowed to cover a portfolio of related IT projects?

For an SCFM, PGE recommends a review similar to the Renewable Automatic Adjustment Clause (aka RAAC). The initial filing establishes eligibility, need, forecast cost, project governance, and proposed treatment. The annual SCFM true-up can verify actual eligible cost, in-service status, material scope changes, and compliance with conditions imposed by the Commission. Material changes should receive additional scrutiny, but settled issues should not be relitigated without a reason.

Supplemental Capital Funding Mechanism Eligibility Across Capital Categories

Staff's Phase 1 materials note that many types of projects may need to use the SCFM. PGE believes eligibility should turn on some combination of these factors:

1) Financial size of the investment;
2) Nature of the investment driver;

3) Demonstration that reasonable alternatives were considered;
4) Good cause finding demonstrating why the MRP index formula and revenue cap are insufficient to address the investment.

Filing Cadence, Decoupling, ESM, and True-Up

To preserve administrative efficiency, PGE supports a standardized SCFM process that consolidates qualifying projects or portfolios into a single filing where appropriate. The process should not reopen settled issues or recreate a general rate case. An annual SCFM review can align with the annual MRP rate update while limiting filing frequency. Decoupling and the SCFM solve different problems: decoupling addresses differences between authorized and collected revenue, while the SCFM determines whether qualifying capital should be added to authorized revenue. For the ESM, approved SCFM revenues and related costs should be reflected consistently so regulatory timing is not mistaken for operating performance. The true-up should reconcile the approved forecast to objective actual information: eligible plant placed in service, final cost, in-service dates, depreciation, taxes, financing impacts, offsets, and amounts already recovered. Material scope or cost changes may require additional explanation and review.

Part 4 - Standardization and Regulatory Pathway

As PGE stated in our previous pre-read[10], the Company supports a layered regulatory approach to establishing an MRP Framework.

Regulatory level	Appropriate role
Administrative rules	Definitions; minimum filing content; timing; materiality framework; used-and-useful and prudence safeguards; no duplicate recovery.
AR 676 Commission Orders	Eligibility principles; standard calculations; true-up treatment; coordination with decoupling and ESM; guidance on planning linkages and cost allocation.
Utility MRP and SCFM orders	PGE-specific projects or portfolios, amounts, evidence, Commission findings, class treatment, and rate implementation.

Conclusion

PGE recommends a framework for capital that:

- Establishes going-in rates through a robust cost-of-service record
- Uses the index for broad annual changes and a targeted SCFM for qualifying capital project(s)
- Maintains distinct, transparent prudence and used-and-useful determinations
- Uses experience from Hawaii and other jurisdictions for design choices while reflecting Oregon needs

[10] Portland General Electric, *AR 676--Portland General Electric, Track 1 O&M Cost Category Pre-Read* (Aug. 21, 2026), Docket AR 676, Public Utility Commission of Oregon. Retrieved from https://edocs.puc.state.or.us/efdocs/HAC/ar676hac348788039.pdf.

Although both the need and cost of capital can face pressures, like exceeding broad inflation trends, PGE believes a balanced MRP Framework can deal with these issues, retain the links between utility costs and cost recovery, and still achieve cost-containment. Please direct questions to JP Batmale at jp.batmale@pgn.com and all formal correspondence and requests to pge.opuc.filings@pgn.com.

Sincerely,

Jason Salmi Klotz

Jason Salmi Klotz
Senior Manager, Regulatory Strategy