NW Natural®

250 SW Taylor Street
Portland, OR 97204

503-226-4211
nwnatural.com

June 3, 2026

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
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Re: AR 676 - Rulemaking to Establish Multi-Year Rate Plan Framework (HB 3179 & SB 688 Implementation)

Northwest Natural Gas Company, dba NW Natural ("NW Natural" or the "Company"), hereby files a joint response on behalf of NW Natural, Avista Utilities, and Cascade Natural Gas Corporation regarding the May 20, 2026 Written Comment Opportunity on the Phase 1 Staff Straw Proposal for the Multiyear Rate Plan (MRP) framework, released by the Public Utility Commission of Oregon Staff.

Please address any correspondence on this matter to me, with a copy to the following:

eFiling
NW Natural
Rates & Regulatory Affairs
250 SW Taylor Street
Portland, Oregon 97204
Email: eFiling@nwnatural.com
Phone: (503) 610-7330

Sincerely,

NW Natural

/s/ Maddie Pulliam

Maddie Pulliam
Rates & Regulatory Analyst

Enclosure

COMMENTS OF NORTHWEST NATURAL GAS COMPANY, AVISTA UTILITIES, AND CASCADE NATURAL GAS CORPORATION

In Response to Staff's May 20, 2026 Straw Proposal

Northwest Natural Gas Company, dba NW Natural, Avista Utilities, and Cascade Natural Gas Corporation (collectively, the "Gas Utilities") respectfully submit these comments in response to Staff's May 20, 2026 Straw Proposal (the "Staff Proposal") filed in this docket.

The Gas Utilities appreciate Staff's continued efforts to advance the development of a Multi-Year Rate Plan ("MRP") framework for Oregon. The Staff Proposal provides a helpful and structured foundation for Phase 1 discussions and appropriately centers key principles, including (1) containing and smoothing customer rate impacts, (2) maintaining utility financial stability, and (3) reducing regulatory burden and improving administrative efficiency.

While the Gas Utilities support these principles and the Commission's objectives under House Bill 3179, several elements of the Staff Proposal, including the prescriptive selection of an index-based revenue cap, the adoption of a uniform five-year plan duration, and a broadly comprehensive scope, warrant further refinement in this rulemaking to ensure that the resulting framework is workable, flexible, and aligned with Oregon ratemaking practices.

General Framework Considerations

The Gas Utilities agree that the establishment of clear principles, goals, and outcomes is an appropriate first step in Phase 1. The key principles are consistent with the Gas Utilities' previously identified foundational concepts, including balancing customer and utility interests, maintaining flexibility, recognizing that ratemaking is not one-size-fits-all, and promoting consistency and predictability in rates and financial outcomes.

It is important to clarify in Phase 2 how the "budget" construct underlying Staff's proposed MRP framework should be developed. Staff's Proposal contemplates a multi-year "budget" established through an index-based revenue cap. Specifically, Staff states: "MRPs should both increase the predictability of rate changes for customers and outline a budget for utilities to stay within." The Gas Utilities emphasize that each such budget must be grounded in utility-specific cost structures and developed through a transparent, evidence-based process. Accordingly, the "budget" should be anchored in a traditional, cost-of-service foundation typically established in a general rate case ("GRC"), which reflects the utility's actual operating costs, capital requirements, and system conditions at a point in time. The GRC is the appropriate forum to establish year 1 of each MRP ("going-in rates") using the methodology employed today (i.e., base year period, adjusted for known changes and other pro forma adjustments for the rate year), from which later annual adjustments would then be applied. While the concept of a multi-year "budget" can support cost discipline, the framework must ensure that such constraints do not override the need to maintain alignment with underlying cost drivers, particularly capital investment needs as discussed further below.

Type of MRP

Staff proposes a uniform index-based revenue cap structure as the foundation of the MRP framework. The Gas Utilities acknowledge that index-based approaches can be an appropriate and effective tool for certain cost categories, particularly where costs exhibit stable, predictable relationships with broader economic indices and where administrative efficiency can be achieved without sacrificing accuracy.

At the same time, indexed approaches require careful calibration and must be evaluated in the context of each utility's cost profile. As previously noted, index-based designs depend on accurate "going-in" rates, well-supported productivity factors, and appropriate inflation measures. If these inputs are not properly aligned, the resulting revenue trajectory can diverge materially from actual costs, particularly for capital-intensive gas utilities managing evolving safety, reliability, and integrity requirements. Such an undesirable outcome would necessitate use of off-ramps or reopeners, which arguably no party nor the Commission would want to entertain.

Rather than relying exclusively on index-based adjustments, the MRP "budget" should be developed using a structured approach that:

- Applies targeted indexing to cost categories that reasonably track inflation,
- Incorporates discrete adjustments for known and measurable costs supported by evidence at the outset of the plan, and
- Preserves supplemental capital and cost recovery mechanisms (e.g., ARMs, deferrals, and trackers) for cost categories that are volatile, policy-driven, or not well-represented by formulaic approaches.

The Gas Utilities emphasize that, while certain O&M components may be reasonably escalated using indices, many cost drivers, particularly capital investments and certain categories of O&M, are better supported through utility-specific forecasts and record evidence. For example, costs that are driven by multiyear contracts, *e.g.,* collective bargaining agreements, are negotiated, arms-length contracts that provide known and measurable costs beyond the first rate year of a multiyear plan. Depending on economic conditions or other exogenous factors, these negotiated costs may exceed inflationary levels and are not controllable to warrant any type of productivity or stretch factor. Additionally, NW Natural operates the Mist underground storage facility that requires significant ongoing well mechanical integrity testing on wells, which is accounted for as an O&M expense. The schedule for this testing is not linear. Certain wells are required to have testing at different timeframes ranging from five to 15 years, which means that in some years NW Natural will test more or less wells than others. An indexed approach will not capture these costs driven by operational and legal requirements.

Capital requirements are often driven by project-specific needs, regulatory mandates, and system integrity programs that do not always follow smooth or predictable inflationary patterns. Similarly, discrete costs such as contracted services, and large-scale projects (e.g., IT systems or infrastructure replacements) may materially affect revenue requirements in ways that are not appropriately captured through broad indexing approaches.

This hybrid approach reflects both Oregon's existing ratemaking practices and the practical realities of gas utility cost structures, ensuring that the MRP "budget" remains disciplined while avoiding structural under- or over-recovery.

Importantly, MRPs are not intended to replace existing ratemaking processes or serve as a mechanism to address all policy objectives. Rather, MRPs should function as an extension of the GRC framework, whereby a GRC (or MRP filing) establishes cost-of-service-based "going in" base rates and an associated revenue requirement, and the MRP governs how those base revenues are adjusted over a defined multi-year period until the next rebasing through a subsequent GRC or MRP. Consistent with this structure, MRPs and GRCs are not the appropriate mechanism to address all categories of costs, particularly those associated with policy-driven initiatives, statutory requirements, or other externally-driven and uncertain requirements which are more appropriately recovered through complementary regulatory tools that better support timely, transparent, and targeted cost recovery while preserving the integrity of the MRP framework.

Accordingly, the Gas Utilities support the consideration of index-based approaches as a foundational component of MRP design, recognizing the benefits such approaches can provide in terms of predictability, administrative efficiency, and cost containment. At the same time, the appropriate application of indexing should be informed by a thorough evaluation of utility-specific cost structures and underlying cost drivers. Phase 1 should therefore establish a flexible framework, while Phase 2 should focus on the design and calibration of the MRP to ensure alignment with each utility's operations. This includes identifying which cost categories are appropriately suited for indexing and which require alternative treatment. A framework that preserves optionality will allow utilities to propose index-based or hybrid structures that are tailored to their specific circumstances and support accurate and sustainable cost recovery.

Plan Duration

Staff proposes a five-year MRP term for all utilities. While longer MRP terms can provide benefits in terms of rate stability and administrative efficiency, a fixed duration may not be appropriate across all utilities or circumstances in this early stage of MRP exploration. The Gas Utilities have emphasized that the viability of longer-term MRPs depends on: (1) the ability to reasonably align revenues with capital and operating costs, and (2) the inclusion of safeguards, such as customer protections, reopeners, and/or off-ramps.

In the absence of these conditions, longer plan durations may increase the risk of revenue misalignment and financial instability. Accordingly, Phase 1 should allow for flexibility in plan duration, particularly as Oregon transitions to an MRP framework. Until Oregon gains more experience with MRPs, it may be appropriate to warrant more limited initial MRP terms to the lower end of the range allowed by statute (i.e., three years in length) to support a measured, informed transition for all parties.

Scope of the MRP

Staff proposes a broad scope for MRPs, incorporating most cost categories into base rates with limited exceptions. Staff has not responded meaningfully to the Gas Utilities' prior comments on this issue. The Gas Utilities respectfully submit that MRPs are not intended to encompass all cost categories. Consistent with longstanding Oregon practice, certain costs should continue to be recovered outside of base rates through other adjustment mechanisms.

In particular, the Gas Utilities emphasize that several existing cost categories are appropriately excluded from an MRP framework in addition to those identified in Staff's Proposal and should continue to be recovered through separate mechanisms:

- **Climate Protection Program ("CPP") compliance costs**: CPP-related costs are externally driven, subject to evolving regulatory requirements, and inherently uncertain in both magnitude and timing. As previously noted, these costs are not well-suited for inclusion in a fixed multi-year budget and should continue to be addressed through deferral or other cost recovery mechanisms until cost behavior becomes more predictable.
- **Low income and customer assistance programs** (including bill discount and arrearage programs): These programs are driven by economic conditions and customer participation levels outside of the utility's control. Recovering these costs through deferral mechanisms ensures that funding levels remain responsive to customer need and are not constrained by an MRP "budget." If these program costs are included in an MRP and have fixed budgets, it may result in limiting customer participation, which goes against the efforts in recent years to make these programs easily accessible for those who need them.
- **Revenue decoupling mechanisms**: Decoupling remains a foundational tool in Oregon to remove throughput risk and stabilize utility revenues in the face of weather variability and policy-driven load reductions (e.g., energy efficiency). These mechanisms are reconciled through balancing accounts and must continue alongside MRPs to ensure revenue neutrality and support financial stability.
- **Regulatory fees, intervenor funding, environmental site remediation and certain other temporary rate adjustments**: These costs are established through statutory frameworks and Commission rules and orders, and are subject to annual cost variability outside the utility's control. As such, they should remain outside of base rates and continue

to be recovered through established mechanisms to preserve transparency and accountability.

- **Statutory based mechanisms:** Statutorily authorized adjustment mechanisms should not be included in base rates within a multiyear plan. The Legislature has already prescribed separate recovery pathways for those costs. For example, ORS 757.396(2) and ORS 757.398(3) expressly direct that RNG-related costs be recovered through automatic adjustment clauses defined in ORS 757.210, which promotes the State's policy goals of reducing emissions through renewable fuels. HB 3179 did not amend these statutes, and therefore did not change the Legislature's directive on how those costs are to be recovered. Embedding such costs in base rates would duplicate or override the statutory framework and undermine the intended separation of cost recovery mechanisms.

More broadly, the Gas Utilities emphasize that Oregon's existing framework already relies on a portfolio of regulatory tools, including deferrals and automatic adjustment clauses, to balance cost recovery, risk allocation, and customer protections. Several of these recovery mechanisms have been extensively litigated, include customer protections, and are integral to the current risk allocation framework for the Gas Utilities. The Commission should undertake a process to determine which costs are appropriate for inclusion in base rates, and which should remain outside of the MRP. This evaluation should consider: (1) utility-specific circumstances and mechanisms, (2) the nature and predictability of the cost, (3) the degree of utility control, (4) the existence of statutory or policy drivers, and (5) the effectiveness of existing recovery mechanisms.

Absent such an assessment, requiring the broad consolidation of cost categories into base rates at the outset of MRPs risks undermining the balance of risk and protections embedded in Oregon's current ratemaking framework and the goals proposed by Staff in this docket.

Finally, it is important to remember that all of the parties and the Commission are starting down a new regulatory path. Not all issues need to be resolved at this time; there will be opportunities for learnings over the first round of MRP filings, and necessary refinements and changes can occur down the road.

Adjustment Factors

Staff's proposal includes an I-X-S+G+Z adjustment framework. The Gas Utilities agree that adjustment mechanisms can provide important flexibility within an indexed framework; however, the design, selection, and application of these factors must be grounded in evidence and informed by utility-specific cost drivers.

At this stage of the rulemaking, the Gas Utilities are concerned that preemptively determining how individual adjustment factors should be structured (or which factors should be excluded) without sufficient analysis and supporting evidence is premature. The appropriate calibration of an indexed framework depends on a detailed understanding of how different cost categories behave over time, which varies meaningfully across utilities and sectors. In particular:

- Inflation indices may not fully capture gas utility cost pressures, especially where costs are driven by industry-specific factors rather than general economic trends;
- Productivity (X) factors require robust, transparent studies tailored to the gas (or electric) utility industry, rather than reliance on generic or imported assumptions from other jurisdictions without evaluating applicability to Oregon conditions[1]; and,
- Capital investment needs (particularly those associated with safety, reliability, and system integrity) may not be adequately represented through formulaic adjustments alone.

As demonstrated in the Gas Utilities' prior comments, gas utility costs may increase at a rate that exceeds general economy-wide inflation, raising concerns about reliance on standard inflation indices without adjustment. Staff's proposal excludes certain mechanisms, such as a K-bar or similar capital adjustment factor, in favor of a supplemental capital funding approach. While the Gas Utilities recognize the concerns raised regarding the use of capital indexing tools, prior comments identify that index-based plans alone may not be sufficient to address the variable and often non-linear nature of capital investment needs. Specifically:

- Capital expenditures are often lumpy, project-driven, and subject to external mandates, making them difficult to reflect through generalized formulaic adjustments; and,
- Other jurisdictions have paired indexed frameworks with separate capital recovery mechanisms to maintain alignment between revenues and investment requirements. For example, Massachusetts has combined index-based revenue cap MRPs with capital trackers and other project-specific recovery mechanisms to support ongoing infrastructure investment, while Connecticut's proposed framework includes both an indexed revenue cap and a customized capital adjustment mechanism ("CT-bar") along with targeted capital trackers for discrete projects. Similarly, Alberta employs an indexed framework supplemented by a two-tier capital funding approach (including a K-bar for routine investment and separate treatment for extraordinary projects), and Hawaii has paired its revenue cap MRP with an Exceptional Project Recovery Mechanism to address capital investments that fall outside "business as usual" spending. These examples demonstrate that hybrid approaches—combining index-based revenue adjustment with distinct capital recovery mechanisms—are a common and practical feature of MRP design.[2]

Additionally, Staff has suggested that certain mechanisms, such as a K-bar or other capital indexing tools, may raise issues under Oregon statute (e.g., ORS 757.355) if they are perceived as allowing recovery of capital prior to an in-service determination and prudence review. The Gas Utilities

[1] The productivity factors for Oregon gas utilities and electric utilities should be determined by a Total Factor Productivity (TFP) study performed by a qualified expert through a competitive solicitation process. The Gas Utilities recommend the competitive solicitation process be led by the utilities.

[2] Current Energy Group, *Multi-Year Rate Plans: Purpose and Design Considerations* (prepared for the Oregon Public Utility Commission, Dec. 11, 2025) at 31-34.

emphasize that any capital recovery approach adopted within an MRP framework must remain consistent with Oregon's longstanding requirement that costs be subject to Commission review for reasonableness and prudency. This fact highlights the need for careful design and calibration in Phase 2, including the development of appropriate procedural safeguards and processes. The Gas Utilities have previously noted that indexed or formula-based structures in other jurisdictions are often paired with separate capital recovery processes, capital monitoring or true-up mechanisms, ensuring compliance with prudence and used-and-useful standards while still providing timely cost recovery.

Importantly, Staff has not addressed the Gas Utilities' prior comments regarding Oregon's ratemaking history.[3] In designing an MRP, it is important to recognize that Oregon already employs several cost-containment mechanisms that materially affect utility risk and incentives. Certain categories of costs—such as market-based compensation for example—are subject to partial recovery, meaning that utilities do not recover these prudent costs in rates. That means that Oregon utilities are at a structural earnings disadvantage because those costs must be incurred to attract and retain our workforce, but those costs are not fully recovered in rates. As a result, authorized revenues are established net of a known category of unavoidable costs, reducing the utility's opportunity to earn its authorized return. To the extent earnings are diminished by structural design, the only lever available to the utility to close the gap is cost control in other areas of the business. These existing limitations must be reevaluated or explicitly accounted for when layering an MRP on top of the current ratemaking framework, to avoid duplicative or unintended restraints on cost recovery.

Accordingly, the Gas Utilities recommend that the Commission avoid pre-determining the inclusion, exclusion, or design of specific adjustment factors, particularly capital-related mechanisms, at this stage, given the importance of grounding these decisions in a more complete understanding of utility-specific cost drivers and how those will interact with the MRP framework. Phase 1 can appropriately establish the guiding principles and overall structure; however further refinement of the individual adjustment mechanisms should be informed by targeted analysis and stakeholder input as the framework is developed. This evaluation should include:

- Evaluation of utility-specific cost drivers and investment profiles,
- Evaluation of how capital investment needs will be supported within the MRP, including whether through indexed mechanisms, supplemental capital factors, ARMs, or other recovery tools, to ensure alignment between revenues and forward-looking system needs,
- Assessment of how adjustment factors interact to maintain appropriate alignment between allowed revenues and actual costs over the MRP term,

[3] See Gas Utilities AR 676 Comments filed on May 6, page 3.

- A focus on establishing design principles that ensure alignment with ORS requirements, including: (1) clear in-service recognition, (2) preserved prudence review, and (3) appropriate Commission oversight processes, and
- Assessment of the existing ratemaking framework and the impact of extending or eliminating some these structures in planning for an MRP.

A more flexible, evidence-based approach in Phase 2 will ensure that the final framework appropriately balances predictability, cost containment, and financial integrity, rather than relying on prematurely specified adjustment mechanisms that may not reflect the underlying cost structure of gas utilities.

Continuation of Revenue Decoupling

The Gas Utilities strongly support the continued use of revenue-per-customer decoupling mechanisms for Gas Utilities under any MRP framework and emphasize that this is a particularly critical time for the Commission to reaffirm that policy.

Decoupling has long been recognized in Oregon as an effective tool to remove throughput risk, mitigate the effects of weather variability and energy efficiency, and support rate stability. Importantly, revenue-per-customer decoupling for gas utilities in Oregon is necessary as State climate policies and Energy Trust-delivered programs intensify energy efficiency efforts that ultimately reduce gas usage. These policies are unrelated to utility performance. Decoupling mechanisms ensure that utilities are able to recover no more or less than the authorized revenues established in their most recent GRC (or, in this case, future MRP) by reconciling differences between authorized and actual revenues, on a per customer basis. This ensures that the gas utilities can remain financially healthy and creditworthy while supporting and implementing State policy objectives, without creating inherent disincentives to fully pursue energy efficiency opportunities.

Decoupling is subject to Commission oversight and remains compatible with both traditional cost-of-service regulation and MRPs. The Gas Utilities emphasize that decoupling is not rendered unnecessary by MRPs and, in fact, complements longer plan terms by stabilizing revenues between rate cases during a period of significant policy-driven change. This mechanism should continue under any future MRP structure and include any deferrals that are transferred into the MRP from existing mechanisms.

Earnings Sharing Mechanism

Staff proposes to include an earnings sharing mechanism ("ESM") as part of the MRP framework. ESMs should not be pre-determined or required in Phase 1. Indexed approaches are expressly designed to place downward pressure on costs by limiting revenue growth relative to an external index. If a utility is able to outperform that constraint through efficient operations, the resulting overearnings are a core feature of the model—not a flaw—as they reinforce the incentive to manage costs. Imposing an earnings test at this stage would dilute that incentive by asymmetrically limiting upside, thereby weakening the very cost containment pressures the index is intended to

create. For that reason, the Commission should first establish the indexed ratemaking framework and evaluate whether its inherent incentives are functioning as intended before layering on additional earnings constraints that could undermine its effectiveness.

Further, the Gas Utilities are already subject to an asymmetrical earnings test that caps upside earnings at the authorized return while leaving full exposure to downside risk, limiting the ability to offset periods of under-earning with outperformance. A symmetrical earnings sharing mechanism, by contrast, applies equally to both over- and under-earnings, allowing customers and utilities to share in outcomes on a balanced basis and preserving incentives for efficient performance while mitigating extreme results.

To the extent the Commission is considering an ESM, it should be designed as symmetrical. Doing so would also require revisiting existing earnings test structures, which may conflict with or undermine a symmetrical approach if left unchanged.

Accordingly, any consideration of ESMs should be deferred to Phase 2 and evaluated after core MRP design elements are established, with any adoption limited to a well-supported, symmetric structure with appropriate deadbands that avoids duplicative earnings constraints and maintains balanced risk allocation.

CapEx/OpEx Equalization

Staff's proposal to pursue CapEx/OpEx equalization is not supported by existing accounting frameworks and represents a significant departure from established U.S. ratemaking practice. Approaches such as TotEx accounting, which effectively capitalize operating expenses, have not been adopted in the United States and raise fundamental compliance concerns under accounting standards.

Given these constraints, further investigation of this concept is unlikely to be a productive use of limited stakeholder and Commission resources. The Commission should instead prioritize development of core MRP design elements that are clearly implementable and grounded in existing regulatory and accounting principles. Efforts to layer on untested and potentially noncompliant constructs risk diverting focus from achievable outcomes and introducing unnecessary complexity into the proceeding.

Performance Incentive Mechanisms ("PIMs")

The Gas Utilities emphasize the importance of distinguishing between MRPs and performance-based regulation mechanisms. MRPs themselves already embed strong incentives for cost containment through reduced regulatory lag and longer periods between rate cases through the adoption of a stay-out commitment.

Staff proposes to include "backstop" PIMs and additional incentive mechanisms. At this early stage, the Gas Utilities do not support treating PIMs as a required component of MRPs for the Gas Utilities based on the requirements in HB 3179. If performance metrics or incentives are

contemplated, the development should be sequenced after core MRP design decisions. Premature adoption of financial incentives or penalties risks unintended consequences without clear evidence that existing incentives due to the MRP design alone are insufficient. These mechanisms do not operate in isolation. The introduction of PIMs can drive incremental utility behaviors and expenditures to meet the policy goal of the PIM, which may increase costs beyond those contemplated in the indexed revenue cap. For that reason, the structure of the MRP should be established first, with any PIMs layered on only after there is a clear understanding of baseline incentives and cost dynamics.

The Gas Utilities further emphasize that the development of performance metrics and PIMs is itself a highly technical and resource-intensive process that requires careful, stand-alone consideration. Establishing effective PIMs necessitates:

- Identifying appropriate and measurable performance areas aligned with clearly defined policy objectives;
- Developing reliable and consistent data sources capable of supporting ongoing tracking and reporting;
- Establishing baseline performance levels and target thresholds that are evidence-based and achievable; and
- Designing incentive or penalty structures that are proportionate, symmetric where appropriate, and free from unintended interactions with other regulatory mechanisms.

This process typically involves extensive stakeholder engagement, iterative testing (e.g., shadow reporting), and validation to ensure that metrics drive intended behaviors without compromising service quality or creating perverse incentives. Importantly, performance design must also consider interactions with existing regulatory tools (including earnings tests, decoupling, and cost recovery mechanisms) to avoid duplicative or conflicting incentives.

Accordingly, the transition to an MRP from a single-year cost-of-service framework should prioritize establishing the core ratemaking structure, as the MRP itself will define the foundational incentives for utility performance. The development of performance metrics and PIMs should

follow as a subsequent and distinct phase of work, after the MRP framework is in place and sufficient experience and data are available to support their design.[4,5]

Conclusion

The Gas Utilities respectfully recommend that the Commission:

- Preserve flexibility in MRP design and duration,
- Ensure accurate and recent "going-in" rates informed by a cost-of-service analysis conducted in a GRC,
- Maintain existing cost recovery mechanisms alongside MRPs, and
- Sequence more complex design elements, such as PIMs and ESMs, for further consideration in Phase 2.

The Gas Utilities look forward to continued collaboration with Staff and stakeholders as this process advances.

/s/Zach Kravitz	*/s/Patrick Ehrbar*	*/s/Michael Parvinen*
Zach Kravitz	Patrick Ehrbar	Michael Parvinen
Vice President, Regulatory Affairs and Resource Planning	Director, Regulatory Affairs	Director, Regulatory Affairs
NW Natural	Avista Utilities	Cascade Natural Gas Corporation

[4] As noted by the Regulatory Assistance Project ("RAP") in its January 27, 2026, presentation, PIMs do not have to be the end-goal of an MRP. RAP also discussed the importance of starting simple when it comes to PIMs, and relying on data that exists today. It highlighted the concept of "shadow reporting" for at least one to three years before implementing financial incentives or penalties associated with PIMs to ensure the metric works as intended. Furthermore, RAP's identified additional best practices of symmetry (i.e., use both rewards for excellence and penalties for failure), simplicity (i.e., focus on 6-12 high-priority PIMs rather than dozens of small ones), and stakeholder collaboration (i.e., defining goals before picking metrics) are reasonable guardrails for the design of an effective MRP framework for Oregon.

[5] Staff has identified TotEx accounting as a potential mechanism used in certain non-U.S. jurisdictions. While the Gas Utilities recognize that this may warrant further exploration, they note that such mechanisms have not been implemented in the U.S., add significant complexity, and may present conflicts with existing accounting principles and frameworks governing regulated utilities. See CT PURA, Docket No. 21-05-15RE01, Draft Decision issued on July 14, 2025, where the Commission determined it may open a separate proceeding to further investigate complex issues that the implementation of TotEx may present.