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May 6, 2026

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
PO Box 1088
Salem, Oregon 97308

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 April 15 Staff workshop material and the subsequent Written Comment Opportunity released by the Public Utility Commission of Oregon Staff on April 17, 2026.

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

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Sincerely,

NW Natural

/s/ Maddie Pulliam

Maddie Pulliam
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Enclosures

Response of Gas Utilities to May 6, 2026, AR 676 Written Comment Request

Northwest Natural Gas Company, Avista Utilities, and Cascade Natural Gas Corporation (collectively referred to herein as the "Gas Utilities") appreciate the opportunity to provide these written comments in response to the Written Comment Opportunity released by the Public Utility Commission of Oregon ("PUC" or the "Commission") Staff on April 17, 2026, under Docket AR 676.

These comments summarize the Gas Utilities comments on Phase 1 issues identified in Workshop #4 held on April 15, 2026.[1] The Gas Utilities have also included initial comments in the "Ratemaking Framework Decision Points" table submitted alongside the written comments that begin to explore Phase 2 issues identified in Workshop #4 on Slides 12 and 13. These comments are consistent with the Gas Utilities' survey response and written comments previously submitted on December 9, 2025, February 20, 2026 and March 16, 2026. The comments included in the table are not intended to be endorsements of any particular multiyear plan ("MRP") framework, but instead are offered to help identify the costs, benefits, and tradeoffs of the various inputs to Oregon's MRP framework. Those comments should be considered in light of the overarching themes presented here.

Principles, Goals & Outcomes

The Gas Utilities support Staff's decision to focus Phase 1 of this rulemaking on establishing foundational principles, goals, and outcomes to guide the development of a multi-year rate plan ("MRP") framework for Oregon. At this stage, clarity around purpose and boundaries is critical to ensuring that later design decisions are coherent, durable, and aligned with statutory requirements.

The Gas Utilities continue to support four core foundational principles for an MRP framework:

1. Balancing customer and utility interests, consistent with the regulatory compact and the Commission's obligation to establish just and reasonable rates.
2. Flexibility over time, allowing the Commission and stakeholders to refine and evolve MRP designs as experience is gained.
3. Recognition that ratemaking is not one-size-fits-all, including differences among utilities and between gas and electric systems.
4. Consistency and predictability, which support rate stability for customers and reasonable access to capital necessary to maintain safe and reliable service.

Consistent with these principles, the Gas Utilities reiterate that MRPs should be oriented toward two priority goals: (1) a predictable and efficient regulatory system, and (2) a high-performing utility business.

[1] Phase 1 issues were identified as (1) Principles, Goals, and Outcomes, (2) Type of MRP, (3) Decoupling, (4) Plan Duration, (5) MRP Scope, and (6) PBR Outcomes. See Workshop #4 Presentation at Slide 11.

These goals support outcomes such as longer periods between rate cases, reduced regulatory lag, gradual and predictable rate changes, continued infrastructure investment, and maintenance of utility financial integrity. While broader policy objectives, such as emissions reductions and equity are important, the Gas Utilities emphasize that MRPs should remain focused on the rate plan, particularly where those policy objectives are already addressed through other statutory or regulatory programs (e.g., Climate Protection Program to reduce emissions, UM 2211 for equity).

Type of MRP (Index-based Cap or Forecasted MRP)

The Gas Utilities do not support prescriptively selecting a single MRP structure. Instead, Phase 1 should establish a framework that allows for hybrid approaches incorporating elements of both indexed-based and forecasted MRPs, recognizing the distinct drivers of gas utility costs.

With respect to capital investments, a capital forecast provides the best support and transparency for what is likely to be placed in service during an MRP because it reflects the utility's specific, project- and program-level plans for execution and in-service timing, rather than generalized trends. Those forecasts are developed through formal planning and governance processes and remain subject to prudence review and other regulatory protections, ensuring that only properly supported investments are ultimately reflected in rates.

In contrast, gas utility capital needs are not driven primarily by inflationary pressures and often outpace inflation due to safety, reliability, and system integrity investments. For example, an individual large project can, on its own, materially increase a utility's capital portfolio in a way that is not well captured by an indexed approach. Reliance on an indexed approach could therefore produce outcomes where a utility's going-in rates reflect a high initial capital profile, while subsequent capital needs decline, creating a risk of systematic over-recovery, or vice versa.

In addition, different categories of capital investment have materially different recovery patterns. For example, large investments in IT or digital systems typically have shorter depreciable lives than traditional gas infrastructure. As a result, two portfolios with similar aggregate capital levels can produce very different revenue requirements over time. A purely indexed MRP would struggle to accommodate these differences.

On the expense side, certain cost components may be reasonably addressed through escalation factors or indexing. However, other O&M costs are known and measurable, such as collective bargaining agreement adjustments and specific contracted services, and do not necessarily correlate with general inflationary pressures. These adjustments may at times be above or below inflation, but where they are known, measurable, and supported by record evidence, they should be reflected in rates, provided the utility demonstrates that the costs are prudent.

Importantly, the Gas Utilities emphasize that MRPs (regardless of the form) cannot be successful if initial rates are significantly misaligned with the cost of service. Establishing appropriate "going-in" rates remains foundational to any MRP design. Accordingly, Phase 1 should preserve

optionality and avoid foreclosing reasonable MRP structures before the Commission has the benefit of the utility-specific data and evidence.

Oregon's Ratemaking History

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.

More broadly, each utility enters an MRP with a distinct regulatory history and set of Commission-imposed mechanisms that shape its risk profile. Those legacy constructs matter. A one-size-fits-all MRP risks misaligning incentives if it assumes a neutral starting point that does not reflect decades of prior Commission decisions.

By way of example, NW Natural is already subject to an annual earnings test that caps earnings at the authorized return on equity. This mechanism is asymmetrical: while the Company bears full downside risk if earnings fall below the authorized level, it is not permitted to retain earnings above that level. As a result, NW Natural does not have the opportunity to offset periods of under-earning with periods of outperformance. Any MRP layered onto this structure must recognize that earnings risk is already constrained on the upside, and that additional caps, indexing constraints, or sharing mechanisms could further skew that balance.

For these reasons, MRP design should be sufficiently flexible to account for Oregon-specific cost recovery policies and utility-specific legacy mechanisms, rather than assuming that all utilities begin from the same regulatory baseline.

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 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.

MRP Duration and Associated Stay-Out Period

The Gas Utilities support a measured and flexible approach to MRP duration, particularly during Oregon's transition to alternative ratemaking frameworks.

While longer plan durations may be appropriate over time, the Gas Utilities note that shorter initial MRP terms allow the Commission and stakeholders to gain experience, evaluate outcomes, and make informed adjustments before committing to longer stay-out periods. Rigidly prescribing plan duration in Phase 1 would risk exposing utilities and customers to unintended consequences if assumptions prove incorrect.

The Gas Utilities further emphasize that longer MRP terms are only feasible if the framework adequately addresses forward-looking capital needs and includes clear safeguards such as off-ramps or reopeners for extraordinary circumstances. Phase 1 should therefore establish principles around duration and flexibility, rather than fixed requirements.

MRP Scope Should Allow for the Continuation of Deferrals Outside of Base Rates

A central and consistent position of the Gas Utilities is that MRPs are not intended to absorb all cost categories. Certain costs remain appropriately addressed through deferrals or other cost recovery mechanisms outside of base rates. The Gas Utilities agree that costs currently recovered through the PGA and Energy Trust mechanisms should continue. However, the Gas Utilities also stress the importance of continuing to recover customer-related costs that support the most vulnerable customer populations (i.e., energy assistance and bill discount programs) through deferral mechanisms. This ensures that the programs customers rely on remain fully funded and supported through rates appropriately. Additionally, any statutorily prescribed cost recovery mechanism, such as an automatic adjustment clause, should not be subject to MRPs. Further, costs associated with any policy-mandated programs that will result in significant costs and

unpredictability driven by weather, such as the Climate Protection Program, should remain outside of base rates.

These cost categories can be unpredictable, significant, externally driven, or tied to specific statutory or policy mandates and should continue to be recovered outside the MRP framework. These tools mitigate inappropriate risk shifting and preserve transparency and oversight.

The Gas Utilities also reject the premise that deferrals and trackers inherently weaken cost-containment incentives. All costs recovered through such mechanisms remain subject to prudency review, Commission oversight, earnings tests, and potential disallowance. Maintaining these tools is therefore consistent with balanced risk allocation and the continued protection of customer interests.

PBR Outcomes and Performance Incentives

The Gas Utilities emphasize the importance of distinguishing between MRPs and performance-based regulation ("PBR") 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.

At this early stage, the Gas Utilities do not support treating performance incentive mechanisms ("PIMs") as a required component of MRPs for the Gas Utilities. If performance metrics or incentives are considered in the future, they should be sequenced after core MRP design decisions, begin with transparency and reporting, and rely on existing data where possible. Premature adoption of financial incentives or penalties risks unintended consequences without clear evidence that existing incentives due to the MRP design alone are insufficient.

Phase 2 Issues

Finally, the Gas Utilities note that it is early in the process to opine on Phase 2 design issues, including detailed index components, earnings sharing mechanisms, capital funding mechanisms, metrics, and off-ramps. These elements are highly interdependent and appropriately considered only after foundational Phase 1 decisions are made.

That said, the Gas Utilities have begun identifying initial considerations and questions informed by the Workshop 4 pre-read materials. These preliminary observations are reflected in the attached worksheet submitted with the Gas Utilities' Workshop 4 comments. These inputs are intended to support Staff's ongoing work and stakeholder dialogue and should not be interpreted as final positions.

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For Stakeholders to Complete: Ratemaking Framework Decision Points

The following table lists MRP and PBR elements that Staff has identified could be subject to decisions in AR 676. Some are expected to be a focus of the Phase 1 Straw Proposal, because identifying these threshold design decisions will clarify the parameters of a Phase 1 interim Commission decision and provide greater focus in Phase 2. Other decision points are included that may receive some attention in a Phase 1 decision, then get fuller attention in subsequent phases of AR 676 or future rate cases. For these, a Phase 1 decision might suggest inclusion or exclusion of certain components, while adoption and design details could take place in a later phase. **Bolded ratemaking components** in the table indicate those that are anticipated to addressed in the Straw Proposal in either of these manners.

Stakeholders are invited to provide perspectives on proposed outcomes and decision points at the April 15, 2026 workshop and through written comments following the workshop. The workshop will focus on a subset of decisions or ratemaking components, while written comments are invited on other areas as well.

Where applicable, the column that lists each MRP and PBR design component includes a reference to the relevant page number in the "Multi-Year Rate Plans: Purpose and Design Considerations" report (MRP Report) from December 2025.

A description of each phase can be located in the Staff Implementation Letter filed in AR 676 in October 2025 and each phase is summarized below:

- Phase 1: Foundations and Concept Development
- Phase 2: Framework Design
- Phase 3: Formal Rulemaking
- Phase 4: Implementation

Ratemaking Component	Options or Considerations	Recommended Approach
Principles, Goals, and Outcomes	See April 8 pre-read filed in AR 676	**Four foundational principles**: balancing customer and utility interests, flexibility over time, recognition that ratemaking is not one-size-fits-all, and the need for consistency and predictability to support stable rates and access to capital **Two priority goals for MRPs:** a predictable and efficient regulatory system (including longer periods between rate cases supported by forward-looking capital recovery) and a high-performing utility business (ensuring financial integrity, continued infrastructure investment, and fair treatment of the Gas Utilities relative to electric utilities) **Establish clear scope boundaries:** Keep MRPs focused on base rates and revenue adjustments while relying on other proceedings for new policy considerations.

Ratemaking Component	Options or Considerations	Recommended Approach
Type of MRP (MRP Report, p. 7)	• Index-based cap (revenue or price cap) • Forecasted MRP	At this stage of the rulemaking, the Gas Utilities do not support prescriptively selecting a single MRP structure for the Gas Utilities. Phase 1 should establish a framework that allows utility specific proposals, rather than predetermining whether an indexed based cap or forecasted MRP will apply. In either case, MRPs cannot succeed if initial rates are significantly misaligned with the capital needs resulting in under-recovery of current and forward-looking costs. (MRPs will default to shorter terms as a result because of regulatory lag). **Forecasted MRP:** - Forecasted MRP rates are more closely aligned and reflective of cost of service - MRP rate years should be reviewed and determined in a GRC - Provides greater transparency surrounding utility-specific capital plans **Index-based cap:** - requires careful calibration of the X factor through a productivity study. Results should be evidence-based and avoid the adoption of generic factors from other jurisdictions without full consideration of the utility-specific circumstances. - "going-in" rates that serve as the starting point for index-based adjustments must be recent and reflective of cost of service - safeguards for customers and the utilities should exist (Z factor for major events, earnings sharing/tests, clear off-ramps, allowance for deferrals/capital funding, where practical/necessary)
Revenue decoupling (MRP Report, p. 40) or other revenue true-up mechanism	How does the existence of decoupling, or not, relate to MRP type?	Revenue per customer decoupling should continue for the Gas Utilities - Revenue decoupling allows for only the revenues approved in the utilities' last GRC to be recovered from customers. - Decoupling removes the impact of weather variability and energy efficiency conservation efforts between rate setting periods. - Decoupling mechanisms can work simultaneously with MRPs. Any impacts of the MRP on decoupling will need to be examined. For instance, changes to rate design may be necessary for any deferrals that are transferred to base rates.

Ratemaking Component	Options or Considerations	Recommended Approach
Plan duration (stay-out period; MRP Report, p. 14)	3-7 years	While the Gas Utilities would support longer-term MRPs in principle, shorter initial terms are more appropriate as Oregon transitions to alternative regulation. - Shorter terms allow the Commission and stakeholders to incorporate lessons learned and refine mechanisms before committing to longer durations. - The Gas Utilities emphasize flexibility: the MRP framework should allow utilities to propose different terms in individual rate cases and to revisit term length as experience is gained. Strict adherence to duration without flexibility for extraordinary circumstances could expose utilities to financial risk if market conditions change significantly. - Longer MRP terms are only feasible if the framework adequately addresses forward-looking capital needs over the length of the term. - Clear provisions should be established for extraordinary off-ramps to address unforeseen events.
Scope of an MRP (inc. trackers and deferrals; MRP Report, p. 11)	Which costs and revenues are consolidated within the MRP base rates and thus subject to associated cost controls?	The Gas Utilities have stated that MRPs are not designed to absorb all cost categories and that existing deferrals, trackers, PGA mechanisms, and similar tools remain necessary to address unpredictable, significant, or externally driven costs without shifting inappropriate risk to customers or utilities. - Some costs cannot be reasonably anticipated or forecasted in a multi-year framework and need separate treatment. For instance, energy supply costs (including purchased gas adjustment) and the Energy Trust of Oregon program funding should continue to be accounted for and evaluated outside of the context of an MRP. - Deferrals that account for specific customer-related programs to address low-income or arrearage forgiveness are subject to economic forces outside of the utility's control that should also be considered outside of the context of the MRP. Unintended consequences may set a cap on the funding available for the programs. - Costs associated with any policy-mandated programs, such as the Climate Protection Program, should remain outside of base rates until the costs of the program can be more readily forecasted and understood over time. - Claims that trackers and deferrals weaken incentives or improperly shift risk are not founded as all costs recovered remain subject to prudency review, Commission oversight, earnings tests, and disallowance risk. These mechanisms are complementary to and not substitutes for traditional cost-of-service or alternative regulation and exist in many other jurisdictions that also operate with MRPs.

Ratemaking Component	Options or Considerations	Recommended Approach
Going-in rates (MRP Report, p. 17)	• What information determines the revenue requirement? • Should a historical or forecasted test year be used?	[Determined in a rate case] The current process for determining the revenue requirement and test year should be maintained. The MRP development is to address the annual revenue adjustments during the period between GRCs. "Going-in" rates that serve as the starting point for an MRP must be: 1) Determined in a GRC proceeding, using the current process (historical test year adjusted for known changes) 2) Recent and reflective of cost of service to support alignment with current and forecasted operational needs - Adequate going in rates are a prerequisite to the success of longer term MRPs. If starting rates are flawed, there is no amount of safeguards (e.g., deferrals, Z-factors/major event, earnings test, etc.) that can correct the misalignment.
ROE (MRP Report, p. 19)	• Do new risks, or mitigants, from the MRP change the ROE? • What influence does authorized ROE have on MRP incentives?	[Determined in a rate case] ROEs should be considered independent of the MRP rulemaking process and determined in a GRC The existence of an MRP, trackers/deferrals or any ARMs, does not reduce utility risk in a way that justifies lowering ROEs. Risk is assessed in the analysis of the ROE determination in a GRC. - Determination of a reasonable ROE requires utility-specific, contemporaneous financial evidence (market conditions, proxy groups, business risk) and therefore must remain within individual GRCs - Despite Commission-approved ROEs, Oregon gas utilities have consistently earned below their authorized returns, which undermines financial stability, worsens regulatory lag, and can increase long-term costs to customers through higher financing costs The Gas Utilities have emphasized that an MRP framework (especially one relying on forecasts or longer plan terms) must be designed so utilities have a reasonable opportunity to actually achieve their authorized ROE when operating efficiently and prudently; otherwise, MRPs will fail to support financial integrity.

Ratemaking Component		Options or Considerations	Recommended Approach
Index-based Adjustments (if applicable)	**Inflation measure (MRP Report, p. 24)**	• GDPPI • Other inflation measures or composite structures (e.g., regional indices, CPI, etc.)	Any inflation measure adopted should be readily available and maintained on a timely basis by a reputable source. - The Gas Utilities have cautioned that gas utility costs have been rising faster than general inflation, citing construction cost data (Handy-Whitman Index) to show that relying solely on economy-wide inflation indices risks systematic under-recovery. This concern is raised as a structural issue with indexed approaches (not tied to a single index choice). Other jurisdictions vary on the inflation index utilized in ratemaking: - GDP-PI published by BEA - Producer Price Index (input-based inflation measure) - Consumer Price Index (output-based inflation measure). Example of other alternatives: Inflation measures in CA rely on both non-labor and labor indices that look at labor changes in the industry as well as a consumer price index for non-labor changes.
	X factor (MRP Report, p. 25)	• How to set (e.g., total factor productivity study)? • Who conducts the study?	X-factor should be set based on a total factor productivity (TFP) study. A competitive RFP process should be used to select a reputable industry expert well-versed in the production of TFP studies across the US and/or Canada and should consider the differences between electric and gas utilities as appropriate. - Concept of the X-factor is intended to mimic a competitive market environment. More productive firms will be able to produce more outputs given the same level of inputs. (Meaning, a productive firm operates with a lower per unit of output cost than other non-productive firms.) - An index-based plan, using an X-factor, allows a utility firm to adjust its revenues by inflation less a productivity factor. Utilities operating in this model are incentivized to perform more efficiently than peer utilities (as determined by the TFP study). - Utility costs are rising at a rate much higher than the general economy-wide inflation due to aging infrastructure, increases in technology, climate policy changes, etc.

Ratemaking Component		Options or Considerations	Recommended Approach
			- Some commissions have adopted zero X-factors to allow for more company-specific cost changes to rates through capital factors, as opposed to a factor that is based on an industry-wide measure based on a sample group.
	Z factor (MRP Report, p. 29)	• What are the criteria to trigger a Z-factor adjustment?	Z-factors (or similar exogenous cost provisions) are appropriate and important safeguards to maintain integrity of the MRP by addressing unforeseen costs outside the normal revenue adjustment framework, rather than forcing premature reopeners or plan termination. The current major-event standards may continue to apply to satisfy the exogenous-cost element of an indexed or interim framework, rather than creating new or higher thresholds. Z-factors can work alongside earnings tests, off-ramps, and prudency reviews, ensuring that utilities remain subject to oversight and disallowance risk while avoiding inappropriate risk shifting. Examples: changes in state or federal law, extraordinary events, and circumstances beyond the utility's control that materially affect financial health, consistent with traditional regulatory practice.
	Stretch factor (consumer dividend; MRP Report, p. 27)	• Is a stretch factor warranted? • What is the adjustment value based on?	Stretch-factor (or consumer dividend) is a credit to customers at the outset of an index-based PBR plan that assumes utilities operating under this model will achieve efficiency gains during the term of the plan and seeks to provide customers an offset to the revenue adjustments for each year the plan operates (or at the outset of the plan). A company with lower unit costs relative to its peers may have less capacity to cut costs. The size of the stretch factor can be based on a cost benchmarking study against peer utilities or history of what other plans have adopted. The determination of the size of a stretch factor is, to a large degree, based on a regulator's judgement and regulatory precedent and does not have a definitive analytical source like the TFP study represents. (Alberta Utilities Commission Decision 2012-237, p. 104).

Ratemaking Component	Options or Considerations	Recommended Approach
Capital funding mechanism(s) (MRP Report, p. 31)	• What projects could be subject to a separate funding mechanism? • What mechanism design is applicable?	ARMs have historically provided limited, focused recovery of specific cost categories (primarily capital) without reopening base rates. They argue ARMs should continue to operate with MRPs and are neither substitutes for, nor inconsistent with, alternative regulation. Core business needs within the control of the utility should be considered for MRPs. Any non-traditional investments (or capital-intensive) that may challenge the operability of a successful MRP should be considered to operate alongside the MRP or given separate consideration within the MRP. Larger projects that are planned to go in-service during the MRP term or discrete capital programs in the capital portfolio may be more appropriately excluded from the base rate MRP plan and separately reviewed and recovered due to either the timing or size of the project/program. Examples can include CIS replacements, other major IT projects, meter modernization. Programs or projects outside of an MRP can provide stakeholders the necessary transparency surrounding specific investments or projects that align with their interests. The company bears the risk of demonstrating that it is executing projects prudently and to the benefit of customers. This review happens today outside of an MRP process.
Earnings sharing mechanism (MRP Report, p. 20)	• Is it symmetric or asymmetric? • Are there tiers and deadbands, and of what size?	The Gas Utilities support continuation of annual earnings tests for transparency and oversight, but indicate that these tests should inform whether thresholds are crossed, not automatically lead to sharing absent a clear, pre-defined mechanism approved in the MRP design. ESMs should be evaluated after core MRP design decisions. Supportive of a symmetric ESM with a reasonable deadband and a sharing structure, ensuring fair treatment for both over- and under-earnings while maintaining strong incentives. Adopt moderate deadbands combined with graduated sharing tiers that can be reviewed over time as parties become more comfortable with the framework and design is established.

Ratemaking Component	Options or Considerations	Recommended Approach
Off-ramp (MRP Report, p. 39)	• What thresholds or criteria could trigger an off-ramp? • How to make these unlikely, but available when necessary?	In most cases, a re-opener or off-ramp is triggered when a utility ROE exceeds or falls below a pre- determined number of basis points relative to the allowed ROE. The triggering event usually commences a review of an MRP plan automatically. The Gas Utilities suggest that the circumstances for terminating an MRP or a re-opening of the MRP be reviewed on a case-by-case basis through a formal proceeding with the Commission. An MRP plan may include the provision for an off-ramp, which allows the utility to apply to terminate the plan altogether when its financial integrity is imperiled. An off-ramp may also be triggered if a change of control is enacted as a result of a merger or acquisition that may require the plan to be terminated to facilitate the transaction.
Reopener (MRP Report, p. 39)	• What thresholds or criteria could trigger a reopener? • How to make these unlikely, but available when necessary?	In most cases, a re-opener or off-ramp is triggered when a utility's ROE exceeds or falls below a pre- determined number of basis points relative to the allowed ROE. The triggering event usually commences a review of an MRP plan automatically. The Gas Utilities suggest that the circumstances for terminating an MRP or a re-opening of the MRP be reviewed on a case-by-case basis through a formal proceeding with the Commission. A re-opener addresses specific problems with the design or operation of an MRP plan that may arise or come to light as the term of the plan unfolds, and which may have a material impact on either the company or its customers which cannot be addressed through other features of the plan. An advantage of a reopener is that it may allow the stay-out provision and the MRP plan to continue with modifications as necessary, without bringing the MRP plan to an end.

Ratemaking Component	Options or Considerations	Recommended Approach
Rebasing (MRP Report, p. 36)	• When does rebasing occur? Based on what information? • How to avoid perverse incentives to inflate costs?	Utility revenues and costs must be periodically re-based so that the benefits of an MRP are passed through to customers, while limiting the inherent administrative inefficiency of cost-of-service ratemaking to the greatest extent possible. Typically occurs at the end of an MRP term following a GRC. Re-basing revenues and costs ensures that efficiency gains achieved in the prior regulatory period are accounted for in the subsequent period to the benefit of customers and that the going-in revenue requirement for the next period is sufficient to maintain the financial integrity of the utility. Capital plans or forecasts should be reviewed in the context of a GRC for the period covering the MRP term.
Efficiency carryover mechanism (MRP Report, p. 38)	• Should an ECM be incorporated? • What structure?	Allows the utility to retain a portion of productivity gains achieved up to the end of the stay-out period for a period of time after the end of the MRP term. ECMs are uncommon in PBR plans in North America. The Gas Utilities do not recommend the adoption of an ECM at this early stage of MRP development.
Capex/opex equalization (MRP Report, p. 36)	• What approach is applicable (e.g., targeted PIMs, capitalization of opex, totex accounting) • What is relationship or connections to capital funding?	The Gas Utilities caution against mechanisms that will present an issue for typical regulatory accounting procedures, such as ASC 980 that relies on an evaluation of cost-based rates, and does not recommend the adoption of a capex/opex equalization mechanism (i.e., RIIO/Totex is not in practice for any utility in the US). Capital plans or forecasts should be reviewed in the context of a GRC for the period covering the MRP term.
Metrics and scorecards (MRP Report, p. 40)	• Which outcomes are subject to metric reporting or a scorecard?	Performance metrics and PIMs should be sequenced after core MRP design as MRPs themselves already provide inherent performance and cost-control incentives. PIMs are not required to be the end-goal of MRPs for gas utilities. The Gas Utilities have cited RAP's workshop presentation; the gas utilities explicitly note that performance incentive mechanisms do not have to be an outcome of

Ratemaking Component	Options or Considerations	Recommended Approach
		MRPs. If adopted at all, they should follow careful goal-setting and evaluation of whether additional incentives are actually needed. If performance metrics are deemed necessary for transparency, the Gas Utilities support starting with simple, non-financial reporting, relying on existing data where possible. They reference best practices such as shadow reporting for one to three years before attaching rewards or penalties to metrics.
Performance Incentives (MRP Report, p. 40-41)	• Which outcomes should be targeted for new or updated performance incentives? • What performance incentive design is most applicable to each outcome (PIMs, SSM, etc.)? • How much revenue should be subject to performance incentives?	See above; additionally, Gas Utilities are not subject to the requirements of SB688.
The relationship between planning processes (DSP, IRP, etc.) and MRPs (MRP Report, p. 44-45)	• How do planning processes inform MRP design and revenue requirements? What timing needs to be taken into account? • How to manage imperfect information or studies subject to later completion?	MRPs should complement planning processes, but remain separate and distinct from IRP planning. The IRP process today for the Gas Utilities in Oregon is a standalone, robust process, requiring submissions every two years, covering a minimum 20-year planning period. The process allows for Commission and stakeholder review and is appropriately focused on least-cost, long-term planning and policy compliance. By contrast, the review, prioritization, and authorization of specific capital projects and near-term capital spending forecasts should occur through a utility's GRC, where investments can be evaluated in detail for prudence, scope, and timing. Capital spending forecasts can also be reviewed in the context of a GRC to understand the customer bill impacts over the MRP term. The Gas Utilities agree with what the Current Energy Report states: "While MRPs primarily address cost recovery and rate stability, system planning processes ensure long-term reliability and compliance with clean energy mandates. IRPs guide generation resource decisions, DSPs focus on grid modernization and distributed energy integration, and clean energy policies drive decarbonization goals. The report emphasizes that MRPs should align with these planning frameworks to avoid conflicting incentives and ensure coordinated investment strategies."

Ratemaking Component	Options or Considerations	Recommended Approach
		Managing imperfect information: Some jurisdictions have allowed for utilities to propose variations of different types of MRPs based on the utility specific needs within the context of their GRCs. For example, Ontario's Renewed Regulatory Framework offers 3 options to the utilities.