STATE OF MINNESOTA
BEFORE THE PUBLIC UTILITIES COMMISSION

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In the Matter of a Commission Investigation into Gas Utility Resource Planning	Docket No. G008,G002,G011/CI-23-117
In the Matter of a Commission Evaluation of Changes to Natural Gas Utility Regulatory and Policy Structures to Meet State Greenhouse Gas Reduction Goals	Docket No. G-999/CI-21-565

Reply Comments of the Citizens Utility Board of Minnesota

The Citizens Utility Board of Minnesota ("CUB") submits these Reply Comments in response to the Commission's Notice of Extended Comment Period issued on May 7, 2024.[1] CUB appreciates the time and effort of those who have participated in this docket's ancillary stakeholder process (the "Gas Utility Innovation Roundtable"), the staff of the Great Plains Institute ("GPI") for facilitating the discussion, and the PUC staff for working with stakeholders to develop this comment procedure. CUB looks forward to reviewing other parties' comments and continuing discussions as the Commission finalizes initial requirements for gas integrated resource planning.

I. INTRODUCTION

In February 2023, the Minnesota Public Utilities Commission (the "Commission") determined that gas integrated resource planning was in the public interest and that Minnesota's three largest investor-owned natural gas utilities—CenterPoint Energy Resources Corp. ("CenterPoint"), Northern States Power Company d/b/a Xcel Energy ("Xcel") and Minnesota Energy Resources Corporation ("MERC") (collectively, the "Gas Utilities")—would be required to file regular natural gas Integrated Resource Plans ("gas IRPs").[2]

The Commission has issued two separate comment periods in this docket. Phase one ended with the February 22, 2024 Hearing, resulting in the Commission's March 27, 2024 Order Establishing a Framework for Natural Gas Utility Integrated Resource Planning (the "Commission's Framework Order").[3] On May 7, 2024, the Commission issued a second comment period, which parties anticipate

[1] *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Notice of Extended Comment Period, Docket No. G008,G002,G011/CI-23-117 (May 7, 2024).
[2] *In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers*, Order Requiring Actions to Mitigate Impacts From Future Natural Gas Price Spikes, Setting Filing Requirements, And Initiating A Proceeding To Establish Gas Resource Planning Requirements, Docket No. G-999/CI-21-135 (Feb. 17, 2023) (hereinafter "Feb. 17, 2023 Order"), p. 2.
[3] *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, Order Establishing Framework for Natural Gas Utility Integrated Resource Planning (Mar. 27, 2023) (hereinafter "Commission's Framework Order").

will be heard before the Commission on September 12, 2024. CUB offers the below recommendations in response to utility Straw Proposal's[4] and parties' Initial Comments filed in this docket.

II. DISCUSSION

A. The Commission's order in this proceeding should provide a comprehensive set of requirements for gas IRPs.

As an initial matter, CUB recommends that, following the next hearing on this matter, the Commission issue a comprehensive final order in this docket that includes all requirements and definitions adopted by the Commission in both phase one and phase two of this docket. Issuing a comprehensive final order that includes all natural gas planning requirements will make the process clear and more accessible to stakeholders moving forward, especially stakeholders who may not have been involved in this docket to date. For this reason, in these comments CUB suggests certain updates to the language from the Commission's previous March 27, 2024 Order.

B. What, if any, additional filing requirements should the Commission adopt for natural gas integrated resource plans (Gas IRPs)?

1. <u>Five-Year Action Plan</u>

In Xcel's Straw Proposal, the Company outlined several requirements for utilities to include in their five-year action plan, focusing on specific information they would need to provide for each project proposed in the plan.[5] CEE and the Department both supported Xcel's proposal, although the Department sought to add language clarifying that all calculations of project cost estimates should include offsetting revenues and tax benefits.[6]

CUB supported Xcel's proposal with the modification that utilities also be required to include a narrative discussion of equity impacts the project may have. CUB continues to support this recommendation and appreciates the additional clarification offered by the Department. We propose the below language to incorporate those changes, and add additional clarifying language:

> <u>For each project proposed in its preferred five-year action plan, t</u>~~T~~he utility~~'s preferred five-year action plan~~ shall include justification of need, resource mix, project scope, construction timeline, ~~and~~ cost estimates <u>including any offsetting revenues and tax benefits, and a narrative discussion of any equity impacts the project may have</u>.

2. <u>Consideration of Minnesota's 2050 GHG Emissions Reductions Goal</u>

The Commission determined that "[t]he scope of integrated resource planning considers the State's economy-wide greenhouse gas reduction statutory goals."[7] Xcel's Straw Proposal proposed additional guidance around the utilities' consideration of those goals and proposed using 2020 as a baseline year

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[4] *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, Xcel Energy Straw Proposal (May 31, 2024) (hereinafter "Xcel's Straw Proposal"); *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, CenterPoint Energy's Straw Proposal (May 31, 2024) (hereinafter "CenterPoint's Straw Proposal"); *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, Minnesota Energy Resources Corporation Straw Proposal (May 31, 2024) (hereinafter "MERC's Straw Proposal").

[5] Xcel's Straw Proposal at 5.

[6] *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, Comments of the Minnesota Department of Commerce at 7 (June 28, 2024) (hereinafter "Department Initial Comments").

[7] Commission's Framework Order at 7, Ordering Paragraph 4.

and incorporating the lifecycle GHG emission factors from filed Natural Gas Innovation Act ("NGIA") plans into its resource analysis.[8]

The CEOs agreed with Xcel's suggestion for a method to calculate emissions reductions and requested the Commission provide additional direction on how this information be incorporated into the plan.[9] The CEOs also recommended that each IRP include the projected emissions that would result from its preferred plan and the other resource mixes considered, including all emissions from distribution system operations and upstream emissions associated with the purchased gas using recognized reporting protocols and available tools.[10]

CEE supported Xcel's proposal and agreed that the state's greenhouse gas goals do not require incorporation of out-of-state emissions in the calculation.[11] However, CEE also highlighted the importance of tracking, reporting and minimizing out-of-state emissions and that this should be done through the IRP process.[12] CEE and the CEOs both supported using the lifecycle emissions factors established in utility filed NGIA plans.[13]

CUB and the CEOs both made similar recommendations for a required narrative description of how the utility's plan would serve the State's greenhouse gas goals.[14] CUB's recommendation included a specific requirement that, if the preferred plan chosen by the utility was not estimated to be on track for achieving the 2050 net zero goals, the utility provide a justification of why the plan was nevertheless chosen as its preferred plan.[15]

CUB remains supportive of Xcel's proposal to use full lifecycle GHG emission factors when evaluating a resource. CUB also supports using lifecycle emission factors from NGIA plans for calculating the lifecycle emissions of different resources.

CUB continues to recommend that utilities include a narrative description of how their preferred plan is or is not in line to meet the states greenhouse gas goals, and we support the CEOs' proposed decision option that IRPs must include projected emissions that will result from its preferred plan, and the projected emissions of the other resource mixes considered.

3. <u>Environmental Externalities</u>

The Commission's Framework Order requires utilities estimate the externality costs of resource options in their natural gas IRPs.[16] Xcel and CenterPoint both recommended in Straw Proposals that the Commission clarify the source of externality values and proposed using the most recent

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[8] Xcel's Straw Proposal at 2.
[9] *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, Comments of the Clean Energy Organizations at 1 (June 28, 2024) (hereinafter "CEOs Initial Comments").
[10] CEOs Initial Comments at 4-5.
[11] *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, Center for Energy and Environment's Comments at 5 (June 28, 2024) (hereinafter "CEE Initial Comments").
[12] *Id*. at 5-6.
[13] CEE Initial Comments at 6; CEOs Initial Comments at 6, n. 14.
[14] *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, Comments of the Citizens Utility Board of Minnesota at 4 (June 28, 2024) (hereinafter "CUB Initial Comments"); CEOs Initial Comments at 4-5.
[15] CUB Initial Comments at 4.
[16] Commission's Framework Order at 8, Ordering Paragraph 17.

externality values adopted by the Commission in Docket No. E999/CI-14-643.[17] CUB noted support for this proposal from CEE, the CEOs, and the Department.[18]

The CEOs noted that, in addition to clarifying which externality values are appropriate to use, the Commission should provide additional guidance about *how* those values are incorporated into the utilities analyses.[19] The CEOs point to the treatment of a regulatory cost of carbon and externality values in electric resource planning, as described by the Commission in its December 19, 2023 Order Addressing Environmental and Regulatory Costs.[20] Recognizing there may be differences in the modeling software or cost-benefit comparison used between gas versus electric resource planning, the CEOs recommend utilities be required to incorporate externality values in the same way they are used in electric side planning, to the degree possible. [21]

We agree with the CEOs that meaningful incorporation of regulatory costs as well as externality costs will be critical to an effective IRP. We support the CEOs' proposed decision option that utilities should include externalities in scenarios in the same manner that electric utilities do, to the greatest extent possible. CUB also continues to support using the Commissions most recent externality cost assumptions with the latest Commission-approved values from Docket No. 14-643.

4. <u>Load Forecasting and Resource Analysis</u>

Pursuant to the Commission's Framework Order, utilities are required to provide a high, medium, and low load forecast in their resource plans;[22] analyze high, medium, and low load scenarios;[23] and analyze high, medium, and low natural gas price sensitivities.[24] CenterPoint's Straw Proposal included an additional description of how the Company envisioned satisfying the plan's required load forecasting stating that, "medium and low forecast ranges will take additional resources into consideration."[25] CenterPoint further elaborated in Initial Comments:

> CenterPoint Energy intends to use currently utilized forecast methodologies to set the high-demand forecast. The medium- and low-demand forecasts will then take into consideration various levels of demand side projects such as electrification and Energy Conservation and Optimization projects. Second, the Company will provide a menu of supply side projects such as transmission pipeline capacity additions, storage, renewable natural gas, hydrogen, distribution system looping, and peaking units to meet the various load forecast scenarios.[26]

In Initial Comments, CEE clarified that the load forecast referred to in Order Point 40 should be a fuel-neutral forecast of energy loads served by the natural gas utility.[27] CEE also stated that the IRP process

[17] Xcel's Straw Proposal at 4; CenterPoint's Straw Proposal at 3.
[18] CEE Initial Comments at 9; CEOs Initial Comments at 6; Department Initial Comments at 5.
[19] CEOs Initial Comments at 6.
[20] *In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subdivision 3*, Docket No. E999/CI-14-643, Order Addressing Environmental and Regulatory Costs at 13 (Dec. 19, 2023).
[21] CEOs Initial Comments at 6.
[22] Commission's Framework Order at 11, Ordering Paragraph 40.
[23] *Id*. at 11, Ordering Paragraph 45.
[24] *Id.* at 11, Ordering Paragraph 46.
[25] CenterPoint's Straw Proposal at 3.
[26] CenterPoint's Initial Comments at 2.
[27] CEE Initial Comments at 10-11.

should consider a variety of alternative energy resource options when evaluating how to serve the natural gas utilities' total energy load—in high, medium and low load forecast scenarios.[28]

The CEOs recommended the Commission provide additional guidance regarding Order Point 6, requiring all resources "be evaluated on a consistent and comparable basis."[29] The CEOs explained that having a standardized cost comparison would ensure all options would be compared on a fair and consistent basis and reference a report by the Environmental Defense Fund that offers a standard methodology called the "*all-in cost metric*" (the "all-in metric").[30] The all-in metric considers both fixed and variable costs, which is essential in capturing ongoing expenses associated with different resources.

In our Initial comments, CUB rejected CenterPoint's characterization that only low and medium demand forecast ranges would take additional resources into consideration.[31] CUB agrees with CEE's description of load forecasting as "fuel-neutral" and continues to maintain that all three load forecast scenarios—including the high load forecast—must consider a wide variety of available resource options.[32] The Commission's Framework Order requires that *all resources* be evaluated on a "consistent and comparable basis,"[33] and that "[a]ll known resources for meeting a utility's load should be considered, including supply-side and demand-side and infrastructure options."[34] The Commission also ordered specific treatment of energy efficiency and demand response resources by the utility:

> Energy efficiency must be treated as an energy resource alongside all other energy resources. Energy efficiency should be included in utility resource analysis and allowed to compete with supply-side and infrastructure resources to determine the optimal level of energy efficiency over the planning period.[35]
>
> Resource plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy and capacity needs.[36]

CUB interprets the Commission's Framework Order as requiring utilities to consider all resources—including energy efficiency and demand response, as well as other demand-side options—in all scenarios to meet its energy need. This does not necessarily mean the utility's IRP will result in a preferred plan that includes all of those resources, just that they be considered and given the opportunity to compete against other supply-side resources like geologic natural gas.

For those reasons, CUB recommends the Commission clarify that utilities are required to consider all commercially available supply-side, demand-side, and infrastructure resources for meeting high, medium and low load forecasts.

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[28] *Id*.
[29] CEOs Initial Comments at 5.
[30] *Id.*
[31] CUB Initial Comments at 5.
[32] CUB notes that the Commission's Framework Order required utilities to "examine all commercially available demand- and supply-side resources and determine a set of available resources," which should then be used in the utility's analysis of resource options for meeting high, medium and low loads. Commission's Framework Order at 11, Ordering Paragraph 44.
[33] Commission's Framework Order at 7, Ordering Paragraph 6.
[34] *Id*. at 11, Ordering Paragraph 8.
[35] *Id.* at 7, Ordering Paragraph 11.
[36] *Id.* at 7, Ordering Paragraph 14.

CUB also agrees it is important to include variable costs and supports the CEOs' proposed decision option to use a consistent methodology to calculate the "all-in" costs of resources to allow for an apples-to-apples comparison.

In its Straw Proposal, CenterPoint also proposed a decision option that would allow utilities to use the design day forecast provided in their most recent demand entitlement fillings to represent the plan's high load forecast, and sales forecast provided in their most recent rate case.[37] In Initial Comments, the OAG did not object to CenterPoint's recommendation with the below modifications to clarify the forecasts used should be those approved by the Commission, rather than what the utility initially proposed, in those proceedings:

> 40.a. Where the high load forecast may represent the ~~Company's~~ Commission-approved forecast for design day as provided in ~~their~~ the utilities' most recent demand entitlement filing, and the Commission-approved sales forecast as provided in the utilities' most recent rate case.[38]

The Department opposed CenterPoint's proposed decision option, citing problems regarding "the significant difference in planning horizons" between demand entitlement filings and the IRPs required 10-year forecast.[39] CUB voiced similar concerns in our Initial Comments and proposed rejecting the decision option.[40]

CenterPoint provided additional clarification in its Initial Comments explaining how the Company would account for the longer-term gas IRP forecast, stating:

> CenterPoint would introduce longer term models which could take into account longer term-focused economic and demographic influences (local, state, regional and national as appropriate) using independent third party forecasts, more efficient appliance end-use saturation surveys, customer/household forecasts, technical and economic potential for next generation gas equipment, potential for fuel switching in the larger industrial classes and the use of 10-, 15- and 20-year weather normal to develop high, mid-range and low growth scenarios. CenterPoint Energy will continue to utilize its current short term forecast methodology for test year projections but the Company will then transition its longer-term scenario forecasts using a modelling structure that has the capability to account for longer term effects.[41]

The CEOs recommended adopting a set of additional parameters, informed by Colorado's Gas Infrastructure Plan rules, to ensure accurate load and customer forecasting. They proposed the following language:

> Each integrated resource plan submitted by a gas utility must indicate how the utility load and customer forecasts incorporate, to the extent practicable, relevant external factors including, but not limited to:

[37] CenterPoint's Straw Proposal at 3-4.
[38] *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, Comments of the Office of the Attorney General, Residential Utilities Division at 3 (June 28, 2024) (hereinafter "OAG Initial Comments").
[39] Department Initial Comments at 5-6.
[40] CUB Initial Comments at 5.
[41] CenterPoint Initial Comments at 2.

(1) The effect of current or enacted state and local building codes and standards;
(2) Building electrification, efficient fuel-switching, and energy efficiency programs or incentives offered by both the gas utility and the local electric utility or local, state, or federal entities that overlap with the utility's gas service territory;
(3) The effects of rate design and/or demand response programs;
(4) Changes in the utility's line extension policies, and the associated impact on gas customer growth; and
(5) The price elasticity of demand (e.g., the impact of reduced throughput and rate increases on sales and peak demand requirements and impacts of commodity prices).[42]

CUB believes the above parameters set out by the CEOs provide an appropriate level of flexibility to utilities while encouraging accurate forecasting. CUB therefore supports the CEOs' proposed load and customer forecast parameters. Moreover, understanding that CenterPoint's clarification in Initial Comments indicates the Company is able to provide the needed 10-year IRP forecast, we do not oppose the Company's proposed decision option 40.a, as modified by the OAG.

5. Scenario and Sensitivity Modeling

Commission's Framework Order Point 48 requires utilities to include "additional analyses of scenarios and sensitivities in their resource plans as directed by the Commission."[43] CUB notes that no utilities or stakeholders have proposed any additional scenario and sensitivity modeling requirements at this time, beyond the existing requirements for high, medium, and low load scenarios and high, medium, and low gas price sensitivities.

In our Initial Comments, CUB supported the below decision option (proposed by Xcel), with slight modification to eliminate duplication of existing Order Points and clarify utilities may still opt to perform additional analysis not specified by Commission order in their plans:

> In initial integrated resource plans, utilities shall, at minimum, analyze scenarios and sensitivities as specified in the March 27, 2024 Order in this docket. ~~The Commission may later order additional scenarios and sensitivities.~~[44]

CEE suggested that Xcel's proposed decision option is not necessary in light of the Commission's existing order language, but do not oppose it.[45] CUB continues to recommend our modified language to Xcel's decision option, as we believe it adds clarification as being a "minimum" requirement. However, in the alternative we support CEE's position that Xcel's proposed decision option is otherwise unnecessary.

6. Modeling Energy Efficiency

CUB continues to support Xcel's proposed decision options regarding energy efficiency, subject to a minor modification, and believes the methodology described by Xcel in its Straw Proposal sufficiently captures the requirements set out in the Commission's Framework Order. CUB recommends striking

[42] CEOs Initial Comments at 7.
[43] Commission's Framework Order at 11, Ordering Paragraph 48.
[44] CUB Initial Comments at 6.
[45] CEE Initial Comments at 11.

"supply-side" so as to not limit energy efficiency from competing against other demand-side and/or infrastructure alternatives as well. CUB continues to recommend the below language:

> The appropriate and cost-effective level of future energy efficiency procurement shall correspond to the maximum program spending level that remains cost-effective when compared to ~~supply-side~~ alternatives.

CUB notes that the Commission's Framework Order has already specified that "[a]ll resources must be evaluated on a consistent and comparable basis" and that:

> Energy efficiency must be treated as an energy resource alongside all other energy resources. Energy efficiency should be included in utility resources analysis and allowed to compete with supply-side and infrastructure resources to determine optimal level of energy efficiency over the planning period.[46]

CUB also agrees with CEE noting that this method may change over time as utilities and stakeholders develop new techniques and approaches to modeling energy efficiency.[47] We hope, as is the case with much of the gas planning process, that the Commission will continue to iterate on these requirements as plans further develop in the future.

7. Expansion Alternatives Analysis ("EAA")

CUB supports the three-step framework for an EAA process outlined by the CEOs in Initial Comments:

> First, the preliminary screening of forecasted infrastructure investments identifies projects for alternatives analyses that are more likely to be feasible and executable based on safety, cost, and timing. Next, to assess whether an alternatives project is technically viable, a utility procures and assembles eligible resources into a portfolio. Finally, a utility evaluates the alternatives portfolio using a benefit-cost test, qualitative vendor criteria, and equity analysis.[48]

i. Additional definitions

CUB expressed in Initial Comments that we have no objection to the additional definition for "capacity expansion project, resource expansion, or new resources" offered by the Gas Utilities, with a minor modification to change the phrase "distribution system" analysis to "expansion alternatives" analysis.[49] CUB also recommended adding additional clarification that projects geographically related and/or interdependent on each other should be considered as a single capacity expansion project under an EAA analysis. CUB continues to make these recommended modifications and is generally unopposed to the utilities' proposed definitions. However, CUB agrees with CEE's Initial Comments noting that Order Point 55 from the Commission's Framework Order renders the last sentence of the utilities' definition redundant and can be struck.

CUB therefore recommends the below modified proposed decision option, incorporating the above changes:

> For the purposes of the natural gas integrated resource plan ~~distribution system~~ expansion alternatives analysis, infrastructure costs shall include capital costs the utility would pay to do the project. Capacity expansion project, resource expansion, or

[46] Commission's Framework Order at 7, Ordering Paragraphs 6, 11.
[47] CEE Initial Comments at 6.
[48] CEOs Initial Comments at 8.
[49] CUB Initial Comments at 11; *see also* Discussion in Section II.E(2).

new resources shall include individual projects, or a set of inter-related facilities needed to meet a specified capacity expansion need due to growth by existing or new customers and facilities. ~~This excludes projects related to routine maintenance, public works accommodation, integrity, reliability, and safety.~~

- Projects that are geographically related and/or interdependent on each other should be considered as a single capacity expansion project for the purposes of determining EAA eligibility above the cost threshold.

ii. Eligible projects and cost threshold

In Initial Comments, the Gas Utilities included an overview of the number of relevant capacity expansion projects each utility has completed over the past five years that were above cost thresholds of $1 million, $3 million, $5 million, $10 million, and $15 million.[50] CUB appreciates the Gas Utilities' willingness to provide this information. The utilities reported the below project counts:

CenterPoint:

Threshold Level	Number of Projects
Above $15 Million	4
Above $10 Million	4
Above $5 Million	4
Above $3 Million	5
Above $1 Million	15

MERC:

Threshold Level	Number of Projects
Above $15 Million	1
Above $10 Million	2
Above $5 Million	2
Above $3 Million	2
Above $1 Million	6

Xcel:

Threshold Level	Number of Projects
Above $15 Million	0
Above $10 Million	0
Above $5 Million	0
Above $3 Million	4
Above $1 Million	6

[50] *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, Xcel Energy Comments at 1 (June 28, 2024) (hereinafter "Xcel Initial Comments"); *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, CenterPoint Energy Comments at 1 (June 28, 2024) (hereinafter "CenterPoint Initial Comments"); *In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G-008,G002, G011/CI-23-117, Minnesota Energy Resources Comments at 6 (June 28, 2024) (hereinafter "MERC Initial Comments").

Additionally, the Department expressed a preference for a single threshold applicable to all three Gas Utilities.[51]

As detailed by CUB[52] and several other parties,[53] the cost threshold must be set at a level that provides an adequate pool of projects from which two to three would ultimately be chosen for a complete alternatives analysis. CUB recognizes that a complete alternative analysis includes a robust and resource-intensive process, made worthwhile by the cost and energy savings a successful alternative project would produce. If the cost threshold is set too low and the pool of eligible projects is limited, it is less likely the EAAs will result in a feasible alternative project and therefore less likely the benefits of an EAA will be realized.

For this reason and based on the Gas Utilities above reporting, CUB recommends a $1 million cost threshold. CUB believes the approximate number of projects identified by each utility above the $1 million threshold is reasonable. Xcel Energy's operating company servicing Colorado (the Public Service Company of Colorado, or "PSCo"), is required to perform a similar alternatives analysis in their Gas Infrastructure Plan and has already completed their first plan approval process.[54] PSCo's project cost threshold is currently set at $3 million, which is the level Xcel currently proposes as its cost threshold for EAA eligibility.[55] However, prior to completing an alternatives analysis, the Company is required to also include preliminary reporting on "system safety and integrity projects"[56] and "mandatory relocation projects",[57] in addition to capacity expansion and new business projects—categories that are currently exempt from the EAA requirement set by the Minnesota Commission.[58] Using these parameters, PSCo's plan captured fifteen projects for which the Company was required to compile an overview. Noting the number of capacity expansion projects reported by Xcel, CenterPoint, and MERC, a $1 million threshold seems to capture a workable number of projects that has been required in other jurisdictions as well.

CUB recommends that the Commission set this threshold in clarification of Order Point 51 in its Frameworks Order, discussed in more detail in Section II.E(2) of these comments, below.

Finally, in Initial Comments, the CEOs acknowledged that the Commission's Framework Order explicitly excludes safety and reliability projects from consideration for an EAA, but nevertheless encourage the utilities to remain open to considering alternatives for such projects where feasible.[59]

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[51] Department Initial Comments at 9.
[52] CUB Initial Comments at 9.
[53] CEE Initial Comments at 14; CEOs Initial Comments at 8; BDC Initial Comments at 2-3.
[54] CUB Initial Comments at 10.
[55] Xcel Initial Comments at 1.
[56] "System safety and integrity projects" are defined as including but not limited to "pipeline and storage integrity management programs; exposed pipe inspection and remediation; pipe or compressor station upgrades; projects undertaken to meet U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration requirements; and Supervisory Control and Data Acquisition (SCADA) upgrades." Colo. Code Regs. 4553(a)(III)(A).
[57] "Mandatory relocation projects" are defined as "a project to relocate the utility's gas infrastructure as required by a federal, tribal, state, county, or local governmental body." Colo. Code Regs. 4553(a)(III)(D) and 4001(gg).
[58] PSCo is required to report on all types of projects in its Gas Infrastructure Plan, however only the capacity expansion and new business projects are eligible for an alternatives analysis.
[59] CEOs Initial Comments at 9.

Although the Colorado Public Utilities Commission also does not currently require safety and reliability projects be considered for an alternatives analysis, in approving PSCo's recent plan they explained why such projects *should* be included:

> To the extent certain system safety and integrity projects are suitable for [non-pipeline alternatives] NPA analysis, given the likelihood of successful alternatives and timing concerns, we strongly encourage the Company to include these projects in its alternatives analysis process. We believe, as potentially true for all project types, alternatives to system safety and integrity projects could offer the potential for meaningful cost savings and other benefits. Customers should not miss out on cost savings available from implementation of an NPA simply because the project it replaces is a safety project.[60]

CUB appreciates that utilities are currently not required to consider alternatives for safety and reliability projects, nor for projects related to public works accommodation, routine maintenance, or integrity. But recognizing the critical opportunity some of those projects may provide for a cost-effective, cleaner alternative, we echo the CEOs' encouragement that utilities remain open to considering alternatives if and when opportunities arise.

iii. Project selection process

With the eligible project cost threshold set at a reasonable level, utilities will have a large enough pool to review projects via a robust project selection process. CUB agrees with CEE's view that the largest distribution system projects may not be those best suited for alternatives, and additional criteria will need to be reviewed to determine which projects from the pool of eligible proposals should move forward for a complete EAA.[61] Xcel identified several examples of criteria that might make a project warrant consideration for an EAA, summarized below:

- Whether a project has a smaller number of directly impacted or served customers and could present cost-saving opportunities.
- Whether a project has a later in-service date within the action period, allowing for a longer timeline to implement the proposed EAA solution.
- Whether the project is in a disproportionally impacted community.
- Whether a project to delivery natural gas service is complicated by factors such as rough terrain, permitting challenges, or limited space.[62]

In Initial Comments, CUB, CEE and BDC also identified several factors that could be considered, including potential for learnings, equity impacts, greater emissions reductions, potential job creation

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[60] *In The Matter of the Gas Infrastructure Plan of Public Service Company of Colorado Filed Pursuant to 4 Code of Colorado Regulations 723-4-4552 of the Commission's Rules Regulating Gas Utilities*, Colorado Public Utilities Commission, Docket No. 23M-0234G, Decision No. C24-0233, Commission Decision Granting, in Part, and Denying, in Part, Application for Rehearing, Reargument, or Reconsideration of Commission Decision No. C24-0092 at 4-5 (Apr. 3, 2024).
[61] CEE Initial Comments at 14.
[62] Xcel Initial Comments at 1-2. Xcel's comments discussed these factors in the context of the Company's proposal to set the EAA eligibility threshold level at $3 million. The Company noted that it could evaluate and select projects for an EAA *below* that threshold where warranted, using, for example, these criteria. While CUB disagrees with Xcel's proposed threshold, we find the factors listed applicable to general consideration of a project—above or below the cost threshold.

and air quality improvement.[63] These are all valuable metrics to use for weighing whether a project is a good candidate for an EAA.

While the above criteria provide an excellent starting point, CUB believe this process will need to be flexible and adapt based on the specific projects available for EAA consideration before each utility. For that reason, CUB continues to recommend that, at least for initial plans, the utilities work with stakeholders in making the project selection determination.[64] As we noted in Initial Comments, CUB hopes the current stakeholder group, facilitated by GPI, can continue and form the foundation for this process.[65] CEE proposed a similar recommendation, and suggested utilities present potential expansion project candidates to the roundtable and collaboratively work with stakeholders to select initial EAA projects.[66] CEE also noted new stakeholders may be interested in joining the Gas Utility Innovation Roundtable meetings to provide input on particular utility IRPs as it relates to their service territory, for example.[67] CEE recommended that GPI, utilities and current participating stakeholders work to engage additional interested stakeholders as the focus of the meetings shift to consider each utility's IRP. We support both of CEE's recommendations and believe such collaboration with stakeholders will provide valuable insight and feedback for the EAA process.

iv. Portfolio evaluation

In Initial Comments, CUB supported Xcel's recommendation that utilities be required to include a narrative discussion of the rationale for the projects selected for the alternatives analysis.[68] We continue to support this proposal and recommend incorporating CEOs' Proposed Decision Option 8, requiring each utility to include a summary of its discussions with stakeholders regarding the project selection process.[69] CUB recommends the below language to reflect that proposal:

> Utility resource plans shall include a discussion of the rationale for the projects selected for an Expansion Alternatives Analysis, and summary of the utility's discussions with stakeholders throughout the selection process.

Once a project has been selected for a full EAA, the utility must complete a robust analysis of possible alternatives. The CEOs proposed additional requirements to clarify what is expected from a utility's EAA, looking to regulations from Colorado's Gas Infrastructure Plans.[70] CUB supports the CEOs' two proposed decision options below, with one minor modification to include an evaluation of air quality impacts that account for a broader range of pollution impacts than just carbon and methane emissions:

> *[CEOs] Proposed Decision Option* (9) A full alternatives evaluation, as required by Order Point 54 of the Commission's March 27 Order, shall include non-pipeline alternatives and/or non-natural-gas alternatives; costs and benefits of those alternatives including the costs of direct investment, variable costs, and the social costs of carbon and methane for emissions due to or avoided by the alternative; air quality impacts; a

[63] See CUB Initial Comments at 14; CEE Initial Comments at 14; BDC Initial Comments at 2.
[64] CUB Initial Comments at 10.
[65] *Id*. at 10.
[66] CEE Initial Comments at 14.
[67] *Id*. at 15.
[68] Xcel's Straw Proposal at 6.
[69] CEOs Initial Comments at 10.
[70] *Id*. at 11-12.

> thorough and transparent explanation of the criteria used to rank or eliminate such alternatives; and an explanation of how equity was considered.
>
> *[CEOs] Proposed Decision Option* (10) To integrate equity into alternatives analyses, utilities shall evaluate ways to overlay maps of proposed capital projects and resource acquisitions across maps of environmental justice and disadvantaged communities in the utilities' service areas.

CUB believes the CEOs' Proposed Decision Option 10 incorporates our recommendation from Initial Comments supporting CenterPoint's suggestion to utilize mapping tools to better analyze equity impacts on communities when evaluating project alternatives.

C. Which utility should file its plan first and why? When should that plan be filed? When should the other utilities file their plans?

In Initial Comments, CUB recommended Xcel be the first utility to file its IRP in late 2026, followed by CenterPoint in late 2027, and finally MERC in late 2028.[71] We continue to recommend this filing order; we believe staggering in one-year increments provides sufficient time in between utility fillings and complies with the Commission's order that the utilities file IRPs once every three years.[72] While CUB appreciates MERC's position as a comparatively smaller utility, we believe a late 2028 filing will provide ample time for the Company to prepare a plan. CUB also supports the Department's recommendation to require filings be made October 1 each year in order to avoid overlap with other common filling dates on November 1, such as general rate cases.[73]

D. For Xcel Energy, what, if any, direction should the Commission give regarding Xcel's analysis and reporting on methane emissions?

In Xcel's Straw Proposal, the Company proposed reporting on currently available methane emissions using recognized protocols, such as the EPA's 40 CFR Part 98, Subpart W.[74] The Department supported this proposal but asked that the utility continue to work with gas suppliers to improve transparency in reporting of upstream methane emissions.[75]

The CEOs asserted methane leakage reporting is a critical piece of emissions calculations for natural gas utilities, considering the high-global-warming potential of the gas.[76] The CEOs recommend requiring all three utilities, not just Xcel, to include the best-available estimates of methane leakage in their plan's emissions calculations.[77] The CEOs also identified an additional tool available for quantifying lifecycle greenhouse gas emissions of delivered natural gas by accounting for fugitive methane and combustion-related greenhouse gas emissions.[78] This tool uses data from the EPA's protocol Subpart W referenced by Xcel and the Department, as well as additional data from the National Energy Technology Laboratory, Energy Information Administration, GREET model, and other sources.[79]

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[71] CUB Initial Comments at 10.
[72] Commission's Framework Order at 8, Ordering Paragraph 21.
[73] Department Initial Comments at 9-10.
[74] Xcel's Straw Proposal at 7.
[75] Department Initial Comments at 10.
[76] CEOs Initial Comments at 4.
[77] *Id*. at 4.
[78] *Id*. at 4.
[79] *Id*.

CUB agrees with the CEOs that methane leakage is an important factor to consider in gas IRPs in order for the utilities and Commission to have a clear understanding of utility emissions. For that reason, CUB supports the CEOs' recommendation that all three utilities be required to report on all emissions from distribution system operations and upstream emissions using recognized reporting protocols and available tools.

E. Are there any other issues or concerns related to this matter?

1. Order Point 36 Clarification

Reviewing the Commission's Framework Order, CenterPoint and MERC both noted in their Straw Proposals that Order Point 36 should be modified to strike the word "electric." CUB supported this recommendation and noted no opposition to this proposal from other parties in Initial Comments. CEE also did not oppose the utility's edit and recognized that in most cases it is difficult for natural gas utilities to have sufficient data and insights into overlapping electric service territories to analyze the likely impact of their IRPs on electric rates and customer bills. However, CEE also recommended that CenterPoint and MERC work with electric utilities in their service territories to understand, to the extent possible, the electric system impacts of resource options in their IRPs.[80]

CUB supports this recommendation, and recommends it apply to all three utilities, including Xcel. Although Xcel is a dual fuel utility in Minnesota and likely has greater access to and understanding of electric-side data, we understand that there are still large portions of Xcel's gas service territory that does not overlap with its electric service. To the degree practical, we recommend all three utilities seek to understand these electric-side impacts.

2. Order Point 51 Clarification

In Initial Comments, CEE provided a description of some confusion among stakeholders in interpretation related to Order Point 51 from the Commission's Framework Order.[81] Order Point 51 states:

> Utilities shall incorporate infrastructure costs related to resource expansion or new resources above an investment threshold to be established at a later date <u>into the resource analysis and selection process</u>.[82]

CUB believes there is confusion about whether the underlined text is intended to make Order Point 51, and in particular the investment threshold requirement, applicable to investments for the sake of the alternatives analysis or to a more general analysis of resource options outside of the EAA. Moreover, the Order Point is positioned under the subheading, "Distribution System Analysis," and precedes Order Point 52, which states, "[t]he alternatives analysis shall be called "Expansion Alternatives Analysis."[83] CUB believes stakeholders are also confused by these features and generally whether a larger distribution system analysis is required in an IRP.[84]

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[80] CEE Initial Comments at 10.
[81] *Id*. at 12.
[82] Commission's Framework Order at 11, Ordering Paragraph 51 (emphasis added).
[83] *Id*. at 11, Ordering Paragraph 52.
[84] CUB notes Xcel's proposed decision option to add an additional definition for "capacity expansion project, resource expansion, or new resources," and our comments regarding the use of the phrase "distribution system analysis" here, which we believe is intended instead to reference the expansion alternatives analysis. *See* Section I.B(7)(i).

CUB agrees with CEE's characterization and understanding of Order Point 51. CEE explained:

> [I]t is our understanding and was our intention that the investment threshold described in Order Point 51 applies only to the selection of projects for the Expansion Alternatives Analysis. We do not believe there should be an investment threshold applied to the broader analysis of resource options in natural gas IRPs.[85]

CUB agrees that the investment threshold set by the Commission will apply *only* to the expansion alternatives analysis. During the first comment period of this docket, CUB recommended that the Commission adopt a "distribution system analysis" made up of two pieces: a capital investment plan and an alternatives analysis (or non-pipeline alternative analysis).[86] However, the Commission determined at the February 22, 2024 Hearing to adopt only the alternatives analysis (renamed the "expansion alternatives analysis") and not require a capital investment plan at this time.[87] For that reason, CUB believes there is no longer a need to reference a general distribution system analysis.

CEE further explains that Order Point 49 speaks to the consideration of infrastructure costs as it relates to a broader resource option analysis, and is intended to encompass *all* infrastructure costs in weighing resource options, *not* just a limited subset based on a threshold limit.[88] Order Point 49 states:

> Natural gas resource plans shall include the cost of each scenario and sensitivity presenting both the utility's revenue requirement and environmental costs and other externalities to the utility's revenue requirement.[89]

CEE explained their interpretation that the utility's revenue requirement, referenced in Order Point 49, would include consideration of *all costs*, including related distribution system and capital costs, associated with the different resource options.[90] CUB agrees with CEE's position on Order Point 49, and understand that no threshold was intended to limit the infrastructure and distribution costs considered in the resource selection process.

As noted above, CUB recommends that the Commission issue a comprehensive final order that includes all requirements and definitions adopted by the Commission in phase one and phase two of this docket. In issuing a final order, the Commission might address the confusion by stakeholders regarding Order Point 51. Specifically, we believe replacing Order Point 51 from the Commission's Framework Order with the below recommended decision option, would clarify the requirements and expectations for the expansion alternatives analysis. CUB notes we collaborated with CEE to align on language for this recommendation:

> Integrated resource plans shall include infrastructure projects related to resource expansion or new resources at or above a $1 million threshold from which utilities select projects for an Expansion Alternatives Analysis. Utility resource plans shall include a discussion of the rationale for the projects selected for an Expansion Alternatives Analysis, and summary of the utility's discussions with stakeholders throughout the selection process.

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[85] CEE Initial Comments at 12.
[86] *See In the Matter of a Commission Investigation into Gas Utility Resource Planning*, Docket No. G008,G002,G011/CI-23-117, Proposal of the Citizens Utility Board of Minnesota at 7, 18 (Oct. 24, 2023).
[87] Commission's Framework Order at 5-6.
[88] CEE Initial Comments at 12.
[89] Commission's Framework Order at 11, Ordering Paragraph 49.
[90] CEE Initial Comments at 12.

3. Deferred Accounting

MERC requests the Commission allow deferred accounting treatment for costs it incurs to engage in integrated resource planning, claiming such costs are "unique, will require rate-making flexibility and will require the Minnesota gas utilities to dedicate significant resources to this effort."[91] As we noted in Initial Comments, the mere fact that a cost has not been recovered through a rate case before does not make it extraordinary and eligible for deferred accounting.[92] On the contrary, the Commission has previously noted:

> Due to the risks of over-recovery, deferred accounting is seldom justified. The Commission authorizes deferred accounting only when good cause is shown that certain costs are unusual, unforeseeable, and large enough to have a significant impact on the utility's financial condition.[93]

The Department "supports granting deferred accounting when a utility meets its burden of demonstrating that it has met the criteria applied by the Commission in various prior proceedings."[94] However, the Department noted "MERC did not provide any analytical support in its Straw Proposal that defines "significant costs" or an estimate of those costs.[95] The OAG, too, observed that MERC has not pointed to any expenses it will incur to engage in resource planning that are large enough to have a significant impact on its financial position.[96]

We also continue to disagree that the costs MERC will incur to engage in resource planning are unusual or unforeseeable. The Commission first ordered a process to establish a gas resource planning requirement in February 2023.[97] MERC has been actively involved in the stakeholder process establishing parameters for gas resource planning in the seventeen months since then. And, according to the proposed timeline emerging in this docket, MERC will not be required to submit its first IRP until late 2028. This means MERC will have had more than five years to "foresee" (and plan and budget for) its first IRP. The mere fact that a cost has not been recovered through a rate case before does not make it extraordinary and eligible for deferred accounting when such costs are incurred to comply with a newly developed requirement that will apply on a regular basis moving forward. For these reasons, we agree with the OAG that "MERC's [deferred accounting] request is premature, seeks to recover out-of-test-year costs simply for participating in the ongoing evolution of the regulatory environment, and risks double-recovery for routine regulatory tasks."[98] We continue to recommend the Commission deny MERC's deferred accounting request.

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[91] *Id*. at 4-5.
[92] CUB Initial Comments at 12.
[93] *In the Matter of Minnesota Power's Petition for Approval to Track and Defer Lost Large Industrial Customer Sales Resulting from the COVID-19 Pandemic*, Docket No. E-15/M-20-814, Order Denying Petition at 5 (May 13, 2021).
[94] Dept Initial Comments at 12.
[95] *Id*. at 12
[96] OAG Initial Comments at 4.
[97] *In the Matter of a Commission Investigation into the Impact of Severe Weather in February 2021 on Impacted Minnesota Natural Gas Utilities and Customers*, Docket No.G-999/CI-21-135, Order . . . Initiating a Proceeding to Establish Gas Resource Planning Requirements at 23 (Feb. 17, 2023).
[98] OAG initial Comments at 1; *see also* Department Initial Comments at 12 (granting conditional approval, or deferred accounting treatment, for capacity expansion projects ordered in a gas IRP proceeding "is not an issue that the Commission needs to resolve at this stage of the gas IRP process).

F. Equity

The Commission's Notice for Comment included several questions for parties and the public to respond to regarding issues of equity and how equity could best be incorporated into utility's natural gas integrated resource planning. CUB appreciates the Commission and stakeholders' attention to this critical issue and, as noted in our Initial Comments, believe gas IRPs are an important space for future planning around issues of disproportionate burden on the gas system.[99]

In its Straw Proposal, Xcel recommended that resource plans include a discussion of how equity was considered in the planning process.[100] CenterPoint noted that mapping tools for low-income residents or disadvantaged communities could be incorporated into the IRP process.[101]

MERC suggested the IRP process could consider how to enhance access to job opportunities in utility industry career areas.[102] However, MERC also suggested that the Commission's Framework Order Point 56—authorizing the Executive Secretary to begin a stakeholder process to consider rate changes needed to maintain affordable and equitable service—is the appropriate venue for the "topic of equity as it relates to utility programs, services and rates," rather than "within the context of the Gas IRP itself."[103] The Department supported Xcel's proposed decision option, and recommended the Commission deny MERC's proposal that equity be addressed by the Executive Secretary rather than within gas IRPs.[104]

As discussed above, CEE recommended GPI incorporate an equity-focused component to the ongoing Gas Utility Innovation Roundtable, and facilitate participation from customers and communities who have been historically been underrepresented in the utility regulatory process.[105]

CUB continues to support Xcel's proposed decision option recommending that resource plans include a discussion of how equity was considered in the planning process. CUB agrees with the Department's recommendation that the Commission reject MERC's characterization that equity issues are better suited for consideration in the stakeholder group ordered in Order Point 56, or generally outside of gas IRPs. As CUB noted in our Initial Comments, we are supportive of MERC's suggestion to consider how to enhance access to job opportunities in the utility industry, and CenterPoint's recommendation to incorporate public data and mapping into gas planning equity analyses.[106] We continue to believe that projects in the utility's five-year action plan and the expansion alternatives analysis are ripe areas for these considerations, and maintain the recommendations in our Initial Comments.

CUB also supports CEE's recommendation to incorporate an equity-focused component to the stakeholder group facilitated by GPI as we move forward with gas planning. We note that our joint recommendation for the Commission to issue a final, comprehensive order that includes the requirements and definitions from both comment periods in this docket is also intended to help improve access to stakeholders and the public who have not participated in the proceeding to date.

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[99] CUB Initial Comments at 13-14.
[100] Xcel's Straw Proposal at 8.
[101] CenterPoint's Straw Proposal at 14.
[102] MERC's Straw Proposal at 7; CUB Initial Comments at 15.
[103] MERC's Straw Proposal at 7.
[104] Department Initial Comments at 14.
[105] CEE Initial Comments at 18.
[106] CUB Initial Comments at 14-15.

CUB encourages all stakeholders, the utilities and the Commission to continue thinking of ways to enhance the consideration and inclusion these issues through the gas planning process, as well as in gas IRPs themselves. We look forward to reviewing the discussion from other commenters on this issue.

III. CONCLUSION

CUB is grateful for the many hours of work and stakeholder engagement parties have contributed to the docket thus far and we thank the Commission for the opportunity to provide these comments. Based on the discussion above, CUB proposes the following recommendations:

Comprehensive, Final Order

- Request the Commission issue a comprehensive, final order in this docket that includes all the requirements and definitions adopted by the Commission, in both phases one and phase two of this docket, for natural gas resource planning in Minnesota.

Five-Year Action Plan

- For each project proposed in its preferred five-year action plan, the utility shall include justification of need, resource mix, project scope, construction timeline, cost estimates including any offsetting revenues and tax benefits, and a narrative discussion of any equity impacts the project may have.

Consideration of Minnesota's 2050 GHG Emissions Reductions Goal

- Each integrated resource plan submitted by a gas utility must include a narrative description of how its preferred plan will support and serve Minnesota's greenhouse-gas-emission-reduction goals. (CEOs)
- Each integrated resource plan submitted by a gas utility must include the projected emissions that will result from its preferred plan and the other resource mixes considered. Projected emissions should include all emissions from distribution system operations and upstream emissions associated with purchased gas using recognized reporting protocols and available tools. (CEOs)
- Require utilities to include consideration of both in-state and out-of-state emissions from the gas system in integrated resource plans.
- Consider the State's economy-wide greenhouse gas reduction statutory goals consistent with Minn. Stat. § 216H.01 and 216H.02.
- Lifecycle GHG emission factors from filed Natural Gas Innovation Act (NGIA) Plans should be considered in resource analysis to ensure lower emissions on a lifecycle basis.

Environmental Externalities

- To estimate environmental externality costs of resource options, utilities shall use the most recent externality values adopted by the Commission in Docket No. E-999/CI-14-643. (Xcel)
- The Commission should clarify that utilities should include externalities in scenarios in the same manner that electric utilities do to the greatest extent possible. (CEOs)

Load Forecasting and Resource Analysis

- Utilities are required to consider all commercially available supply-side, demand-side, and infrastructure resources for meeting high, medium and low load forecasts.

- The Commission should require utilities to use a consistent methodology to calculate the "all-in" costs of resources to allow for an apples-to-apples comparison. (CEOs)
- Each integrated resource plan submitted by a gas utility must indicate how the utility load and customer forecasts incorporate, to the extent practicable, relevant external factors including, but not limited to:

  (6) The effect of current or enacted state and local building codes and standards;

  (7) Building electrification, efficient fuel-switching, and energy efficiency programs or incentives offered by both the gas utility and the local electric utility or local, state, or federal entities that overlap with the utility's gas service territory;

  (8) The effects of rate design and/or demand response programs;

  (9) Changes in the utility's line extension policies, and the associated impact on gas customer growth; and

  (10) The price elasticity of demand (e.g., the impact of reduced throughput and rate increases on sales and peak demand requirements and impacts of commodity prices). (CEOs)

<u>Scenario and Sensitivity Modeling</u>

- In initial integrated resource plans, utilities shall, at minimum, analyze scenarios and sensitivities as specified in the March 27, 2024 Order in this docket.

<u>Modeling Energy Efficiency</u>

- To treat energy efficiency alongside all other energy resource options, utility integrated resource plans should evaluate energy efficiency achievement scenarios including expected program achievement to maximum achievement. (Xcel)
- The appropriate and cost-effective level of future energy efficiency procurement shall correspond to the maximum program spending level that remains cost-effective when compared to alternatives.

<u>Expansion Alternatives Analysis</u>

- For the purposes of the natural gas integrated resource plan expansion alternatives analysis, infrastructure costs shall include capital costs the utility would pay to do the project. Capacity expansion project, resource expansion, or new resources shall include individual projects, or a set of inter-related facilities needed to meet a specified capacity expansion need due to growth by existing or new customers and facilities.
  - Projects that are geographically related and/or interdependent on each other should be considered as a single capacity expansion project for the purposes of determining EAA eligibility above the cost threshold.
- *Replace Order Point 51 from the Commission's March 27, 2024 Order with:*
  Integrated resource plans shall include infrastructure projects related to resource expansion or new resources at or above a $1 million threshold from which utilities select projects for an Expansion Alternatives Analysis. Utility resource plans shall include a discussion of the

rationale for the projects selected for an Expansion Alternatives Analysis, and summary of the utility's discussions with stakeholders throughout the selection process.

- Require utilities to work with stakeholders in selecting which projects undergo the complete expansion alternatives analysis.
- A full alternatives evaluation, as required by Order Point 54 of the Commission's March 27 Order, shall include non-pipeline alternatives and/or non-natural-gas alternatives; costs and benefits of those alternatives including the costs of direct investment, variable costs, and the social costs of carbon and methane for emissions due to or avoided by the alternative; air quality impacts; a thorough and transparent explanation of the criteria used to rank or eliminate such alternatives; and an explanation of how equity was considered.
- To integrate equity into alternatives analyses, utilities shall evaluate ways to overlay maps of proposed capital projects and resource acquisitions across maps of environmental justice and disadvantaged communities in the utilities' service areas. (CEOs)

Utility Filing Schedule

- Require the following schedule for utilities to file their initial gas integrated resource plans:
    - Xcel to file on October 1, 2026
    - CenterPoint to file on October 1, 2027
    - MERC to file on October 1, 2028

Order Point 36 Clarification

- Strike the word "electric" from Order Point 36 of the Commission's March 27, 2024 Order.
- Require gas utilities work with electric utilities in their service territories to understand, to the degree practical, the electric system impacts of resource options in their IRPs.

Deferred Accounting

- Deny MERC's deferred accounting request.

Equity

- Integrated resource plans shall include a discussion of how equity was considered in the planning process. (Xcel)
- Incorporate an equity-focused component to the Gas Innovation Roundtable stakeholder group.

Respectfully submitted, July 19, 2024

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