MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**January 21, 2026**	**Agenda Item **2**
Company	• CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas • Minnesota Energy Resources Corp • Northern States Power Co. d/b/a Xcel Energy	
Docket No.	E-999/CI-07-1199; E-999/DI-22-236; E-999/CI-14-643	
	In the Matter of 1) Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06. 2) Establishing an Updated 2022 Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minn. Stat. § 216H.06. 3) Further Investigation into Environmental and Socioeconomic Costs Under Minn. Stat. § 216B.2422, Subdivision 3. **With Implications for:** a Commission Investigation into Gas Utility Resource Planning (Docket no. G-008,G-002, G-011/CI-23-117) **AND** 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)	
Issues	What are the appropriate data sources and values for the regulatory cost of greenhouse gas emissions for Xcel Energy, CenterPoint Energy, and Minnesota Energy Resource Corporation's upcoming gas integrated resource plans?	
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✓ **Relevant Documents** | **Date**

Relevant Documents	**Date**
Request for Comments, Minnesota Department of Commerce and Pollution Control Agencies	September 8, 2025
INITIAL COMMENTS	
CenterPoint Energy	October 31, 2025
Fresh Energy, Minnesota Center for Environmental Advocacy (MCEA), Sierra Club	October 31, 2025
Xcel Energy	October 31, 2025
Department of Commerce (listed as Nov. 3 in eDockets)	October 31, 2025
REPLY COMMENTS	
LIUNA Minnesota / North Dakota	November 21, 2025
Xcel Energy	November 21, 2025
CenterPoint Energy	November 21, 2025
Minnesota Energy Resources Corporation (MERC)	November 21, 2025
Fresh Energy, Minnesota Center for Environmental Advocacy (MCEA), Sierra Club	November 21, 2025
Department of Commerce	November 21, 2025
Public Comment Durgésh Manjuré of EPRI	November 21, 2025

Additional Relevant Documents filed in Docket no. 23-117 (Methane Emissions Reports)	**Date**
Compliance Filing- CenterPoint Energy	October 27, 2025
Compliance Filing- Minnesota Energy Resources Corporation (MERC)	October 28, 2025
Compliance Filing- Xcel Energy	October 28, 2025

Table of Contents

I. Background

This briefing paper discusses establishing the estimated range of "costs to comply with any regulation of greenhouse gas emissions" for gas utilities to use in forthcoming integrated resource plans (IRPs) by drawing on the following three requirements.[1]

First, Minn. Stat. § 216H.06 requires the Commission to "establish an estimate for the likely range of costs of future carbon dioxide regulation on electricity generation" to "be used in in all electricity generation resource acquisition proceedings." The estimated range has been updated at least every other year since December 2007 (Table 1). The update is made following a notice and comment period in docket no. E999/CI-07-1199 led by the Minnesota Pollution Control Agency (MPCA) and Department of Commerce (Department).

Table 1. Commission estimates for future CO_2 regulation and procedural cadence

Dept. & MPCA Notice Issue Date	Order Issue Date	Lower Bound in $ /ton for CO_2	Upper Bound in $ /ton for CO_2	Start Year to apply costs in resource planning
Sept. 19, 2007*	December 21, 2007	4	30	2012
Dec. 15, 2008*	October 8, 2009	9	34	2012
Dec. 17, 2010*	June 3, 2011	4	34	2012
July 23, 2012*	November 2, 2012	9	34	2017
October 18, 2013	April 28, 2014	9	34	2019
December 3, 2015	August 5, 2016	9	34	2022
August 22, 2017	June 11, 2018	5	25	2025
July 9, 2019	Sept. 30, 2020	5	25	2025
June 30, 2022	December 19, 2023	5	75	2028
Sept. 8, 2025	-	-	-	-

*Commission issued notice of comment.

Most recently, on September 8, 2025, the Department and MPCA solicited input on the 1) range of regulatory costs of CO_2 emissions, 2) the appropriate threshold year for the application of the value range, and 3) the method to consider environmental costs and regulatory costs.[2] The Department and MPCA requested comments be received by November 7, 2025. The

[1] Order Clarifying and Expanding Framework for Natural Gas Integrated Resource Planning issued October 28, 2024 in docket nos. G-008,G-002, G-011/CI-23-117 and G-999/CI-21-565, comprehensive gas IRP requirements, quoted text from ordering paragraph 15

[2] Request for Comments issued September 8, 2025 by the MN Pollution Control Agency and the Department of Commerce in Docket No. E999/DI-25-345 and Docket No. E999/CI-07-1199.

Department said it will address comments and set values in docket nos. 25-345 and 07-1199.[3]

Second, this briefing paper draws on requirements for gas IRPs, text quoted from Order language[4] with underline emphasis added:

- Utilities should address risk and uncertainty of demand, availability, and price for all resource options included in resource plans, and costs to comply with any regulation of greenhouse gas emissions.[5]
- 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.
  - The Commission delegates authority to the Executive Secretary to open a comment period in docket no. E999/CI-07-1199 to consider and determine the appropriate data source and values for the regulatory cost of greenhouse gas emissions for natural gas resource planning through the upcoming docket to update the regulatory cost of carbon for electric resource planning.

On August 25, 2025, the Commission sought input on these gas IRP requirement by asking the following. The initial comment period closed October 31 and replies closed November 21, 2025.

- Are the regulatory cost values established for Minn. Stat. 216H.06 and most recently approved on Dec 19, 2023 in docket no. 07-1199 appropriate for use in upcoming gas IRPs?
- If the current values are *not* appropriate, what data source and update timeframe should be used for regulatory cost of greenhouse gas (GHG) emissions values for natural gas?
- How recommendations impact the need for modeling inputs for Xcel's IRP due July 1, 2026?

By October 31, 2025, initial comments were filed by CenterPoint Energy (CPE), Minnesota Energy Resources Corporation (MERC), Xcel Energy (Xcel), Fresh Energy, Minnesota Center for Environmental Advocacy (MCEA), and Sierra Club (filing jointly), and the Department. The Department requested additional information in replies pertaining to Xcel's accounting for and

[3] Department of Commerce initial filing made October 31, 2025 in docket nos. E999/CI-07-1199; G008, G002, G011/CI-23-117; and G999/CI-21-565 at 7.

[4] Order Clarifying and Expanding Framework for Natural Gas Integrated Resource Planning issued October 28, 2024 in docket nos. G-008,G-002, G-011/CI-23-117 and G-999/CI-21-565, comprehensive gas IRP requirements at ordering paragraphs 15 and 54.

[5] Minn. Stat. § 216H.01 provides that “"Statewide greenhouse gas emissions" include emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride emitted by anthropogenic sources within the state and from the generation of electricity imported from outside the state and consumed in Minnesota.” The Statute also mentions the combustion of natural gas as a contributor to statewide emissions as observed by Department in initial comments in this docket at 7.

modeling[6] of regulatory costs as well as CPE, MERC, and Xcel's natural gas delivery data as reported to the EPA and the accounting for costs to produce those data (**Appendix**).

By November 21, 2025, reply comments were filed by CPE, MERC, Xcel, LIUNA, Fresh Energy, MCEA, and Sierra Club (filing jointly), Durgésh Manjuré of EPRI, and the Department.

Third, this briefing paper draws on the following requirement for Xcel, CPE, and MERC to:

> [R]eport methane emissions from natural gas distribution system operations using available reporting protocols in the natural gas integrated resource plan until a system specific leakage estimate derived from measured leakage from the utility distribution system is available. Within 12 months of the October 28, 2024 order, each utility shall file a report including the capital and O&M costs of procedures for system specific leakage rates measurements and a description of their current practices.[7]

By November 3, 2025, CPE, MERC, and Xcel made compliance filings on methane emissions. Staff draws on these filings to develop a baseline understanding for current levels of and spending on methane (CH_4) emissions. This is because Minn. Stat. § 216H.06 only discusses estimated future costs for regulation of carbon dioxide (CO_2) but utilities were Ordered to consider GHG emissions more broadly.

II. Layout of Briefing Paper

In Staff's view, decisions made at the agenda meeting will set up a process for incorporating simple, accurate, and "evergreen" regulatory cost data into gas IRPs. These issues are before the Commission:[8]

- Consideration of regulatory costs of methane and/or carbon dioxide regulation
    - Which emissions- direct, downstream, or upstream and/or the scope (1-3)- to which utilities will apply the estimated cost of GHG regulation.

[6] The Commission's October 28, 2024 Order in docket nos. G-008,G-002, G-011/CI-23-117 and G-999/CI-21-565 the stakeholders DELIBERATELY did not include the word "modeling" in gas IRP requirements, choosing instead the broader term "analysis." Therefore, to require the same modeling for gas IRPs as is required for electric may not be appropriate.

[7] Order Clarifying and Expanding Framework for Natural Gas Integrated Resource Planning issued October 28, 2024 in docket nos. G-008,G-002, G-011/CI-23-117 and G-999/CI-21-565, comprehensive gas IRP requirements at ordering paragraph 52.

[8] Staff notes that commenters also discussed the authority of the Commission to establish guidance on the regulatory cost of GHG emissions for gas IRPs. Staff omitted this discussion from briefing papers as no decision options were offered, no one disputing the Commission's authority filed a reconsideration at the issuance of the Order requiring regulatory cost in gas IRPs, and groups questioning Commission authority also recommended values for the regulatory cost to be used in gas IRPs.

- Source(s) of data to inform estimated upper and lower bounds of estimated costs to comply with GHG regulations
- Upper and lower bounds of estimated costs
  - Required scenarios
- Effective date on which regulation is estimated to start and factor into resource costs
- Timing for each of the gas utilities to incorporate costs into their IRP

III. Methane and / or Carbon Dioxide

EPRI pointed out that while the Commission's Notice and Order both referenced greenhouse gases, the proposed docket from which to source values for regulatory cost only referenced carbon dioxide. EPRI noted that for the different greenhouse gases, there are "differences in emissions sources, abatement opportunities, uncertainties, and climate effects, there are different marginal abatement cost ranges associated with each GHG."[9] Thus, EPRI recommended clarifying if methane and / or CO_2 equivalent values were also of interest.

The Department as well as Fresh Energy, MCEA, and Sierra Club (joint commenters) believe that the future regulatory costs of both CO_2 and methane emissions should be considered. Xcel, in contrast, advocated for a focus only on the costs to reduce methane from oil and gas production and transmission upstream. Xcel said that emissions upstream of a LDC would be a better fit for the purpose of the gas IRP. The EPA rules Xcel referenced could, Xcel stated, "impact natural gas supply commodity prices in alignment with the scope of this application in natural gas IRPs."[10]

Staff notes the definition provided in Minn. Stat. §216H.01, Subd. 2: "Statewide greenhouse gas emissions" include emissions of carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride emitted by anthropogenic sources within the state…" as well as the guidance given in the Commission's October 28, 2024 Order which required consideration of regulatory costs for GHGs, not exclusively carbon dioxide.[11] As will be discussed later in this briefing paper, the Department and the Joint Commenters provided methods to include separately the regulatory costs of methane and carbon dioxide.

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[9] EPRI comments made by Durgésh Manjuré originally received November 21, 2025 in docket nos. E999/CI-07-1199; G008,G002,G011/CI-23-117; G999/CI-21-565 at 5

[10] Xcel initial comments made October 31, 2025, DOCKET NOS. E999/CI-07-1199; G008, G002, G011/CI-23-117; G999/CI-21- 565, at 2 and quoted text at 4

[11] Order Clarifying and Expanding Framework for Natural Gas Integrated Resource Planning issued October 28, 2024 in docket nos. G-008,G-002, G-011/CI-23-117 and G-999/CI-21-565, comprehensive gas IRP requirements at ordering paragraphs 15 and 54.

IV. Data Source

A. Carbon dioxide based on electric IRPs

The Department supported using the values for estimating regulatory cost in electric IRPs, as guided by Minn. Stat. §216H and Minn. Stat. § 216B.2422, to also estimate cost of regulatory compliance in gas IRPs. The Department reached this conclusion by considering definitions of GHG found in Minn. Stat. §216H and used in the Natural Gas Innovation Act (NGIA) which include carbon dioxide and methane. The Department also found this data source appropriate based on the Legislature's goal to reduce emissions.[12]

Fresh Energy, MCEA, and Sierra Club also supported using the same values for electric and gas IRPs. The joint commenters defended this position because per the most recent order in docket no. 07-1199, the value chosen for use in electric IRPs was selected because it is the value required as a tax or fee on carbon to limit global temperature rise to 2^{o}C. The value is based on a global effort to limit climate change, not the effort of one sector specifically.[13] Therefore, reasoned the joint commenters, regulatory costs should apply equally to CO_2 emissions from the electric and gas sectors.

Xcel and CPE disagreed with using the same values for gas and electric IRPs. Xcel said that the regulatory cost was developed for electricity generation not for gas. Instead, costs for natural gas supply-side resources should be tailored to "sector-specific risks and regulatory mechanisms" as well as unique market dynamics.[14]

CPE disagreed, in principle, with the use of a regulatory cost at all, as such a cost could be de facto regulation, not a means for accurate planning. As reductions in GHG are not required for individual sectors and thus, **"**[T]he regulatory cost of carbon itself is not intended to serve as a form of regulation. Ultimately, CenterPoint Energy is concerned that leveraging the regulatory cost carbon as a decarbonization tool instead of as an input intended to improve the accuracy of utility models will result in the establishment of regulatory cost values that far exceed actual anticipated near-term regulatory costs.**"**[15]

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[12] Department initial comments made October 31, 2025, Docket Nos. E999/CI-07-1199; G008, G002, G011/CI-23-117; and G999/CI-21-565 at 14

[13] Fresh Energy, MCEA, Sierra Club (Joint commenters), initial comments made October 31, 2025, Docket Nos. E999/CI-07-1199; G008, G002, G011/CI-23-117; and G999/CI-21-565, at 2 citing Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06, Minn. PUC Docket No. 07-1199, Order Addressing Environmental and Regulatory Costs (Dec. 19, 2023) at 12.

[14] Xcel initial at 1

[15] CPE initial comments made October 31, 2025 in Docket Nos. G008,G002,G011/CI-23-117; G999/CI-21-565; G999/CI-07-1199 at 3

Further, CPE believed that planning for a carbon tax would stifle the innovation that CPE is pursing in NGIA. The pilots developed in NGIA, once introduced into IRP analyses and subject to such a carbon tax may not be viable technologies for widespread deployment.[16] The Department, however, disagreed with the logic that innovation could be stifled by a carbon tax. The Department argued that in considering NGIA pilot projects like gas heat pumps and renewable natural gas (RNG), "it is unclear to the Department how that hindrance would occur. With everything else held constant, a higher upper regulatory cost of carbon applied to anthropogenic sources like stoves that use geologic gas, would result in a favorable economic comparison of RNG to geologic gas."[17]

B. Methane based on EPA RIA

The Department, Xcel, CPE, MERC, and the joint utilities recommended considering regulation of methane emissions when estimating regulatory costs for gas IRPs. Recommendations by the Department and Xcel used the same source to determine how to assign costs to each ton of methane emitted. Both referenced the Environmental Protection Agency's (EPA) Regulatory Impact Analysis (RIA) for the November 2021 proposal, 86 FR 63110, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." The proposal covered

- New Source Performance Standards (NSPS)
    - for the crude oil and natural gas source category
    - Under Clean Air Act for existing crude oil and natural gas
- Emissions Guidelines (EG)
    - Under Clean Air Act, re: States' plans to establish performance standards to limit methane emissions.

The November 2021 proposal was bolstered by the November 2022 supplemental rulemaking in the form of methane limitations; the November 2022 RIA is referenced by the Department.[18] The December 2023 document finalized actions undertaken in November 2022; this RIA is referenced by Xcel.[19]

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[16] CPE initial at 3

[17] Department replies made November 21, 2025 at 4

[18] RIA of the Supplemental Proposal for the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (Nov 2022) https://www.epa.gov/system/files/documents/2022-12/Supplemental-proposal-ria-oil-and-gas-nsps-eg-climate-review-updated.pdf see table 4-5.

[19] RIA of the Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (Dec 2023) https://www.epa.gov/system/files/documents/2023-12/eo12866_oil-and-gas-nsps-eg-climate-review-2060-av16-ria-20231130.pdf see table 1-3 and 1-6.

The Department relied on the RIA's impacts on natural gas commodity prices under the final NSPS and EG to create its required value for the 2024-2026 Triennial for Gas Environmental Compliance Impacts. The values selected was 1.4% of the $/MCF commodity cost for use in the time period 2024 – 2045. The Department referenced the RIA table, shown below as Table 2, extrapolated US prices to fill in each year 2023-2035, and averaged the values to produce 1.4%.[20] The Department recommended using that same 1.4% value as the regulatory cost of methane in gas IRPs. Note, the RIA concluded that "The maximum projected annual decreases in both oil production and natural gas production exceed benchmarks for adverse effects."[21]

Table. 2 Estimated Natural Gas Production and Prices Changes under Proposed NSPS and EG

	2023	2025	2026	2030	2035
US Onshore Production (million Mcf/yr)	-.02%	-.05%	-1%	-.73%	-.63%
US Prices (2019$/Mcf)	.04%	.12%	2.35%	1.7%	1.47%

Xcel used the same EPA proposal but a different RIA and set of values from that RIA, shown in Table 3. Xcel used projected methane reductions under the NSPS and EG as well as the cost to achieve those reductions. In deriving its final recommended bounds for the regulatory compliance cost for methane, Xcel divided the compliance cost at 2% discount by the projected reductions. The joint commenters supported Xcel's methodology stating, "the values for compliance costs relied on by Xcel are more analogous [than the Department's methodology] to the regulatory cost values the Commission are attempting to create for use in gas utility regulatory planning."[22]

Table 3. Cost of methane reductions under EPA proposal

Period	Net Compliance Cost PV for NSPS and EG	Total Methane Emissions Reductions
2024-2030	$19,000 (2% discount); $18,000 (3% discount); $14,000 (7% discount)	1,500 million metric tons of CO_2 equivalent

Staff notes that to calculate the regulatory cost of methane emissions, Xcel's approach in this docket

[20] Department of Commerce Decision In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities, Docket No. E,G999/CIP-23-46, March 31, 2023, at 252 https://efiling.web.commerce.state.mn.us/documents/%7B00DF3887-0000-C719-B71B-0523B746A81D%7D/download?contentSequence=0&rowIndex=1

[21] RIA December 2022 at 4-8 section 4.1.3.4. https://www.epa.gov/system/files/documents/2022-12/Supplemental-proposal-ria-oil-and-gas-nsps-eg-climate-review-updated.pdf

[22] Joint commenters replies made November 21, 2025, at 2

Cost in \$ per metric ton CO_2e = compliance cost ÷ projected emissions reductions

is like the Company's approach in its NGIA plan. In its NGIA plan, Xcel's proposed portfolio of NGIA pilots were submitted to the Commission alongside a set of project metrics. These metrics included "GHG Abatement Cost" which was calculated using the net present value (NPV):

\$/ ton = total resource cost ÷ lifetime lifecycle emissions reductions

Though the above equation was submitted as an NGIA pilot project metric, Xcel noted, "the Company prioritized submitting a compliant portfolio which, per the NGIA statute, considers costs and benefits broadly, not just the quantified project costs and the cost per ton of GHG emissions reduction."[23] To this extent, the Commission's Order did not mention abatement costs as a justification for approval of Xcel's NGIA plan.[24]

Though Staff finds the comparison to NGIA useful because both of Xcel's approaches are focused on the cost of pollution abatement, the goal of NGIA is, Per Minn. Stat. § 216B.2427, to contribute to meeting the state's greenhouse gas and renewable energy goals. Thus, while the NGIA equation above is related to cost per projected emissions reductions, it is not a reflection of expected policies or their impacts.

C. Context

As acknowledged by the joint commenters, above, and explained in the Commission's most recent Order, an International Monetary Fund (IMF) paper is the basis for the upper bound of the regulatory cost of carbon dioxide.[25] The IMF paper focused on establishing a global price floor for carbon, varying based on a country's income, that could also guide any site-specific policy levers. This floor was shown to limit global warming to 2^{o}C. CPE recognized that the IMF paper relied on global values and stated that while it, "does not dispute the intent of the analysis that gave rise to this value, we do not have reason to believe that such regulation is being contemplated at the state or federal level."[26]

EPRI advocated instead for a Minnesota-specific study as, **"**the values relevant to gas utilities operating in Minnesota should reflect the marginal costs of abating natural gas-related emissions in Minnesota.**"**[27]

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[23] Xcel 2023 NGIA Plan Petition, December 15, 2023, docket no. G002/M-23-518 Exhibit F – Part C, quote at 7.

[24] Order approving natural gas innovation plan with modifications, May 16, 2025, docket no. G002/M-23-518

[25] Jean Chateau, Florence Jaumotte and Gregor Schwerhoff, Why Countries Must Cooperate on Carbon Prices, IMFBlog (May 19, 2022); https://blogs.imf.org/2022/05/19/why-countries-must-cooperate-oncarbon-prices-2/

[26] CPE replies made November 21, 2025, at 3

[27] EPRI comments at 3

Xcel suggested that a focus on Federal regulations was sufficient, stating that compared to the EPA rule, discussed in the next section, and other Federal regulations, "additional state level regulations are unlikely to have a significant impact on market prices."[28]

D. Commission decisions

To close this section, the Commission may decide if it is appropriate to use the above data sources as sources for the regulatory cost of GHG emissions values in gas IRPs. Within this larger question, the Commission can consider:

- Are values developed for electric generation in docket no. 07-1199 appropriate for use in gas IRPs? (**Decision Option 3**)
- Are values derived from EPA RIAs for the crude oil and natural gas sector appropriate for use in gas IRPs? (**Decision Options 1- 2**)
- By finding any of the above data sources appropriate, does the Commission wish to have an "evergreen" source of data for gas IRPs- establishing a practice of drawing on the same sources for subsequent IRPs? (see **Decision Options 1-3**). To this decision, Staff notes that the Commission's October 28, 2024 Order *did* delegate authority to the Executive Secretary to open this comment period to consider and determine the appropriate data source and values for the regulatory cost of greenhouse gas emissions for natural gas resource planning.
- Are global-level analyses appropriate for estimating regulatory impacts for utilities operating in Minnesota? Alternatively, would a yet-to-be-conducted Minnesota-specific study be more appropriate?

V. Bounds

A. Methane emissions upper bound for regulatory cost = $13

MERC, CPE, and the joint commenters agreed with Xcel's calculation of $13 for upper bound of costs for regulation of upstream methane emissions. Using data from December 2023, Xcel calculated the value by dividing compliance costs by predicted required emissions reductions under EPA NSPS and EG using a 2% discount rate. Xcel does add a note of caution that these EPA rules were developed under the previous administration (Biden) and questioned the appropriateness of using a value within the context of a new administration. To this extent, Xcel also proposed a lower bound of estimated regulatory costs, below.

While agreeing with Xcel's chosen value, the joint commenters disagreed with implications of that value. Xcel's chosen value reflects only methane leakage, which is only a portion of gas system emissions, but Xcel is using that value to represent regulation of ALL gas system emissions; the joint commenters find this an unreasonable assumption. "Moreover, EPA

[28] Xcel initial at 5

estimates that these regulations would cover roughly 80% of methane leakage, not 100%. Because methane leakage is a relatively small fraction of overall gas production, these regulations only attempt to address around 10% of all emissions from gas production and use. Approving values based on these regulations alone as applicable to the entirety of gas production and usage assumes that there will be no future regulations—either state or federal—aimed at addressing emissions from the other 90% of gas produced and actually achieving our state or national climate goals."[29] To remedy, the joint commenters suggest *also* including the regulatory cost of carbon dioxide when utilities apply regulatory costs in their resource plans, see below.

B. Methane emissions lower bound for regulatory cost = $0

The utilities recommended setting the lower bound of emissions for the regulatory cost of methane at zero dollars. The utilities justified this position by suggesting that, for a variety of reasons, there may be no regulation in future and more, the current administration has no interest in limiting emissions. In initial comments, CPE hypothesized a future with no regulatory costs; regulatory costs could be unnecessary

- If emissions declined and no additional policy was needed
- If near term climate action was all carrots, no sticks
- As, currently, at the Federal level, there is little interest in carbon reductions so likely there will be limited future carbon regulation.

The joint commenters and the Department disagreed with a lower bound of zero dollars because this would mean the future would have no regulation of GHGs at the state or federal level. More, "A $0 value for the regulatory cost of carbon would be inconsistent with recent Commission Orders. In its December 2023 Regulatory Costs Order, the Commission declined to set the lower bound of the regulatory cost value at $0**"** and see Table 1. Last, the Department referenced the Commission's October 28, 2024 Order instructed utilities to consider <u>any</u> costs to comply with GHG emissions regulation, emphasis added, which would imply that some cost must be considered.[30] Thus, The Department recommended that CPE's and Xcel's proposal to use a lower regulatory cost of carbon value of $0 should be rejected.

[29] Joint commenters replies at 3 and explaining, *Xcel does not specifically discuss to which emission categories the cost range it is proposing would apply. And citing One Minnesota-specific study estimated that "methane leakage contributed 16 percent of total lifecycle greenhouse gas emissions associated with Minnesota's natural gas consumption in buildings and industry." Center for Energy and Environment & Great Plains Institute, Decarbonizing Minnesota's Natural Gas End Uses (July 2021) at 79 n.95 (citing Audrey Patridge and Rabi Vandergon, It All Adds Up: Emissions from Minnesota's Natural Gas Consumption, Center for Energy and Environment (December 3, 2020)). And citing Key things to Know About EPA's Final Rule to Reduce Methane and Other Pollution from Oil and Natural Gas Operations (Dec. 2, 2023).

[30] Department of Commerce reply comments in Docket Nos. E999/CI-07-1199; G008, G002, G011/CI-23-117; and G999/CI-21-565 on November 21, 2025, at 5, citing 5 Order Addressing Environmental and Regulatory Costs, December 19, 2023, Docket Nos. E-999/CI-07-1199, E-999/DI-22- 236, and E-999/CI-14-643.

Staff notes that when it comes to including a zero value in utility planning, the Commission's December 2023 Order offered guidance after stating that it was, "not persuaded that $0 represents the best estimate of the cost of future CO2 emissions... The Commission notes that some utilities include in their resource plans scenarios that omit consideration of CO_2 costs—in effect, assuming a CO2 cost of $0. While the Commission will decline to require utilities to develop such scenarios, utilities will remain free to do so."[31]

C. Methane emissions lower bound for regulatory cost = $9

The joint commenters recommended that instead of setting a lower bound of $0, the Commission set a bound of $9 for gas utilities to use to plan for the regulation of upstream methane emissions. The joint commenters arrived at this value by performing the same calculation as Xcel but using values associated with a 7% discount rate, rather than the 2% discount rate used by Xcel.[32]

D. Methane emissions regulatory cost should be calculated using a 1.4% adder

The Department recommended using the values from the ECO cost-effectiveness framework, 1.4% of the $/MCF commodity cost of natural gas, for regulatory costs related to methane emissions.[33] Staff notes that in the most recent ECO triennial discussions, for 2027-2029, the proposed value for use in ECO/CIP is 1.0%.[34] The Commission would need to decide, if supporting the Department's recommendation, if and when it would require use of updated values.

E. Carbon dioxide emissions regulatory cost = $5 to $75 per ton of CO_2e

The Department found it appropriate for the Commission to use the same values in gas IRPs as electric IRPs. The joint commenters agreed, stating that a range of $5 to $75 per ton of CO_2e

[31] Order Addressing Environmental and Regulatory Costs, December 19, 2023 in 07-1199 at 13, with footnote that, "in contrast, the Commission has directed utilities to include at least one scenario that excludes environmental costs. See In the Matter of the Quantification of Environmental Costs Pursuant to Laws of Minnesota 1993, Chapter 356, Section 3, Docket No. E-999/CI-93-583, Order Establishing Environmental Cost Values (January 3, 1997) at 33 (directing utilities, in proceedings to select resources, to generate at least one scenario that analyzes only "the direct cost of resources without regard to environmental externalities"); Environmental Cost Order at 58 (" In resource-selection proceedings, utilities shall continue to analyze potential resources under a range of assumptions about environmental values—including at least one scenario that excludes consideration of environmental externalities.")"

[32] joint commenters replies 3

[33] Department of Commerce Decision In the Matter of 2024-2026 CIP Cost-Effectiveness Methodologies for Electric and Gas Investor-Owned Utilities, Docket No. E,G999/CIP-23-46, March 31, 2023, at 252 https://efiling.web.commerce.state.mn.us/documents/%7B00DF3887-0000-C719-B71B-0523B746A81D%7D/download?contentSequence=0&rowIndex=1

[34] https://mendotagroup.com/mn-cost-effectiveness-ac/

emissions is appropriate for gas utilities to use to plan for regulation of end-use emissions.

F. Carbon dioxide emissions regulatory cost = -$50 to $50 per ton of CO_2e

LIUNA recommended a broader range of values to account for regulatory cost of carbon. They chose a broad range to represent a decade and a half of dramatic climate policy changes at the Federal level and more, to capture the speculative nature of trying to understand future costs. LIUNA cited the recent rollback of policies that would have economically incentivized carbon free resources and thus dismissed with the values proposed by the joint commenters as wishful thinking, not likely regulatory outcomes.

Ultimately, LIUNA would prefer no value to be assigned to regulatory cost of carbon as doing so may inaccurately weight some resources in favor of others in the gas utilities' IRPs. However, if Commission decides to adopt a value, LIUNA recommended choosing one that can represent the full range of pendulum swings and under which each utility can "characterize and justify" the values selected.[35]

G. Influence of values chosen

CPE was concerned about the values selected for the estimated bounds of regulatory cost because the choices for the upper and lower bounds influence the base / reference case a utility would use in its scenarios.[36]

However, Staff notes that in the Commission's Order, "Xcel expresses concern that adoption of this figure [$75 high end regulatory cost] will have an inappropriate consequence for its reference case scenario, which Xcel models based on the highest regulatory costs. The Commission notes, however, that it has not required Xcel to adopt that practice."[37]

H. Commission decision

With respect to the content of this section, the Commission will need to determine the values it will direct utilities to use in their gas IRPs to estimate the regulatory costs of GHG emissions. The Commission can consider the values for upper and lower bounds of regulatory costs for

- Upstream methane emissions (**Decision Options 5-10**)
- End-use carbon dioxide emissions (**Decision Options 11-13**)

VI. Emission Scope

Emissions may be considered in relationship to the emitter; they may be described as

[35] LIUNA comments November 21, 2025 in Docket Nos. E999/CI-07-1199; G011/CI-23-117; G999/CI-21-565

[36] CPE initial comments at 5

[37] Order Addressing Environmental and Regulatory Costs, December 19, 2023 in 07-1199 at 13

Upstream, Midstream, Direct, or Downstream[38] or as Scope 1-3[39].

The Department and the joint commenters support the inclusion of costs for the regulation of methane leakages upstream of the utilities **and** for carbon dioxide from end-use emissions. As justification to consider emissions broadly, the Department noted a discussion on emissions in CPE's NGIA proceeding. Specifically, per Minn. Stat. § 216B.2427, the only constraint in defining "emissions" is that the emissions must come from an anthropogenic source. As such, the "source of greenhouse gas emissions could range from a large industrial facility to a gas stove in someone's home."[40]

Further, the joint commenters said, "In planning terms, this [regulatory] cost represents the future expenditures utilities will likely incur to comply with future regulations directed at CO_2 emissions (e.g., a carbon tax). It should be applied to projected gas consumption, paralleling how electric utilities apply the cost to forecasted demand and emissions from electricity generation. However, the gas sector also faces significant methane emissions from leakage in the system prior to the delivery of gas to customers."[41]

The utilities disagreed. As CPE pointed out, "The reality is that the statutory language used to establish the regulatory cost of carbon does not draw clean lines around which future regulatory costs are, or are not, included within the value. What language is provided considers electricity generation, not electric end-uses."[42]

To this extent, Xcel proposed a focus on upstream and midstream emissions, stating that the cost of carbon regulations fall on upstream producers' methane emissions and pipeline operators, not Local Distribution Companies (LDCs).[43] "Regulatory carbon costs apply only to supply-side resources, influencing procurement strategies and competitive dynamics among gas alternatives."[44] CPE supported Xcel's position saying that "Xcel Energy's interpretation that regulatory costs impacting the manufacturing and transportation of natural gas can, and should, be considered within the regulatory cost of carbon is legitimate. Further, framing the regulatory costs around gas supply and commodity prices is in-line with the initial intent of gas

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[38] https://www.afpm.org/newsroom/infographic/infographic-downstream-midstream-and-upstream

[39] Homepage | GHG Protocol

[40] Department of Commerce initial filing made October 31, 2025 in docket nos. E999/CI-07-1199; G008, G002, G011/CI-23-117; and G999/CI-21-565 at 10 citing In the Matter of CenterPoint Energy's Natural Gas Innovation Plan, Order Denying Reconsideration, January 13, 2025, Docket No. G-008/M-23-215

[41] Joint commenters initial at 3

[42] CPE replies at 4

[43] Xcel replies made November 21, 2025, at 3

[44] Xcel replies at 2

IRPs, which was to reduce exposure to high gas costs and market volatility in the wake of Winter Storm Uri."[45]

However, while the utilities envisioned a regulatory cost that only applies to upstream producers, the Department questioned ability to measure upstream emissions. The Department noted that utilities often buy gas from pooled resources and often from sources outside of the country.[46]

In sum, CPE acknowledged the disagreement among commenters "regarding what these regulatory costs represent within a gas IRP and how they should be applied in the modeling process."[47]

A. Staff analysis

The Commission could decide which emissions to require utilities to factor into their gas IRPs. Alternatively, the Commission may allow the utilities to choose and then provide an opportunity to comment on those choices in the first gas IRPs. The Commission's Order allows for either of these two options; see comprehensive requirement paragraphs:

> 15, Utilities should address risk and uncertainty of demand, availability, and price for all resource options included in resource plans, and costs to comply with any regulation of greenhouse gas emissions.
>
> 54, 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.[48]

If the utilities were to decide which emissions to apply regulatory costs, it seems they have proposed to apply costs to the gas sector equivalent of electricity generation- the natural gas producers who would emit methane "upstream." See Figure 1.

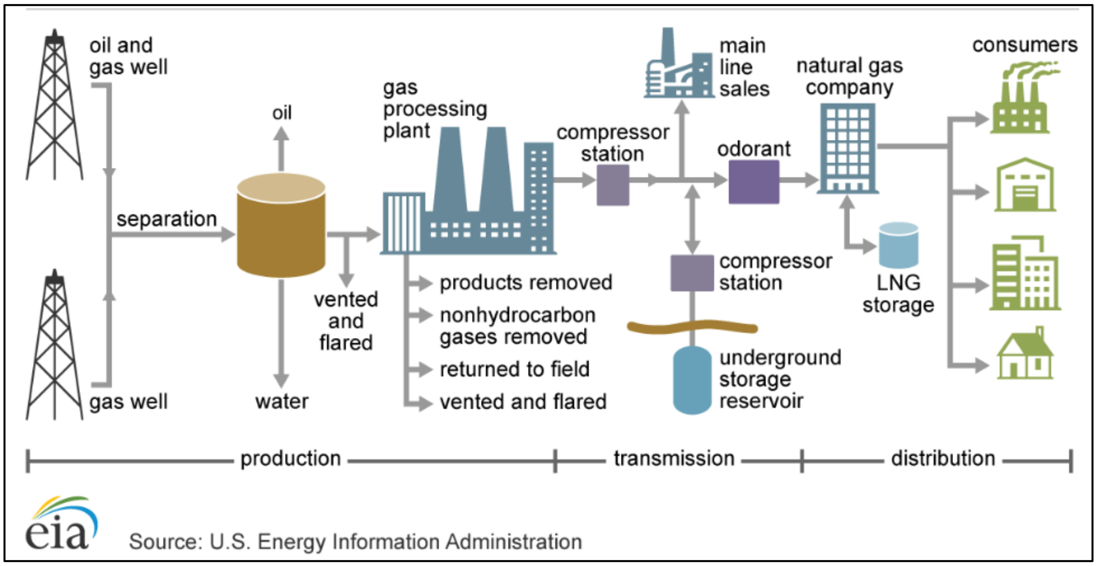
Figure 1. Natural gas production and delivery

[45] CPE replies at 4

[46] Department replies at 10

[47] CPE replies at 4

[48] Comprehensive IRP requirements are included in the Order Clarifying and Expanding Framework for Natural Gas Integrated Resource Planning issued October 28, 2024 in docket nos. G-008,G-002, G-011/CI-23-117 and G-999/CI-21-565. Note, per comprehensive requirement paragraphs 48 & 49, utilities shall analyze high, medium, and low load scenarios AND high, medium, and low natural gas price sensitivities in their resource plans.



The Commission can contemplate if such application is appropriate, as utilities may not have accurate information about the gas they purchase nor a choice in their gas source:

1. In Xcel's most recent gas rate gas, the Company explained it had removed upstream certified natural gas (CNG) from its 2030 goal- net-zero methane emissions on Xcel's system by 2030- as CNG has not proven to be scalable in Minnesota.[49]
2. Issues with quantifying upstream emissions has been discussed at length in the Commission's Performance Based Regulation docket (E002/CI-17-401) and this proceeding.[50]

Staff notes that the Commission appears to still be undecided about what upstream data are available and as such, has required that "CenterPoint, MERC, and Xcel must include in their gas IRPs additional information about upstream emissions data availability."[51]

Staff now introduces the language of emissions "scope." The utilities' preferred application of regulatory cost would be to the emissions associated with the gas purchased for subsequent distribution. As other entities are using energy to unearth and refine that gas, the emissions associated with upstream gas would be considered a scope 3 emission.[52]

Scope 3 includes all other emissions within the Company's value chain, including the use of

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[49] Lyng direct testimony by Xcel Energy in docket no. 25-356 at 10

[50] See discussion in staff briefing paper for September 12, 2024, agenda meeting, filed in docket nos. G008,G002,G011/CI-23-117 and G999/CI-21-565 at 19-22.

[51] Order Clarifying and Expanding Framework for Natural Gas Integrated Resource Planning issued October 28, 2024 in docket nos. G-008,G-002, G-011/CI-23-117 and G-999/CI-21-565 at paragraph 13

[52] https://www.mckinsey.com/featured-insights/mckinsey-explainers/what-are-scope-1-2-and-3-emissions

natural gas by consumers. Scope 3 emissions are indirect emissions. Scope 2 are also indirect; scope 2 emissions are associated with the generation of energy that is purchased by a Company. Considering scopes 2 could mean that the Company quantifies the emissions of the energy it purchases to undertake its regular operations.

Quantification of scope 3 emissions could also include application of regulatory cost value to monthly gas sales, e.g., from the Annual Automatic Adjustment (AAA) Report filings like information on Distribution of Over/Under Recovery by class,[53] as AAA filings are reviewed by the Department and the Commission.

To the extent that scope 2 or 3 emissions may be considered for application of regulatory costs, the gas IRP explicitly requires utilities to consider lifecycle emissions, see below; however, as CPE pointed out, there is no guarantee future regulation would include lifecycle analyses[54]:

> The scope of integrated resource planning considers the State's economy-wide greenhouse gas reduction statutory goals.
>
> a. CenterPoint, MERC, and Xcel shall consider lifecycle GHG emission factors from filed Natural Gas Innovation Act (NGIA) Plans in resource analysis to ensure lower emissions on a lifecycle basis.[55]

Beyond scopes 2 & 3 there are additional aspects of a gas LDC's business that could be suited for regulatory cost application. Indeed, compared to upstream emissions, LDC gas utilities have information about and more control over Scope 1 emissions. Scope 1 / direct emissions are those that come from a Company undertaking its daily operations. For Xcel gas, this is the emissions from its vehicles its employees drive to read meters, emissions from heating and cooling its buildings, and leaking and venting associated with its distribution system. With respect to pipes in particular, utilities already provide data on emissions and pipe condition in service quality dockets and to the Pipeline & Hazardous Materials Safety Administration (PHMSA; Tables 4 & 5).

Table 4. Pipe Type in 2024

Utility	**Type**	**Cathodically Protected Coated Steel**	**Plastic**	**System Total**
CPE	Miles of Mains	3,247.263 (21.9%)	11,520.924 (77.9%)	14,796.1
	# of Services	37,920 (4.7%)	765,652 (94.8%)	807,599

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53 See, for example, CPE filing August 29, 2025, Docket No. G-999/AA-25-98, Exhibit 2B

54 CPE initial filing at 3

55 see comprehensive gas IRP requirements with Order issued October 28, 2024, at ordering paragraph 4. Indeed, per Xcel's NGIA proposal in docket no. G002/M-23-518, Lifecycle GHG intensity of certain innovative resources and associated pilot emissions reductions potential were calculated using the GREET model. Within their use of the GREET model, utilities must file low, expected, and high GHG emissions intensity estimates.

MERC	Miles of Mains	1,380.92 (25.4%)	4,053.58 (74.6%)	5,434.5
	# of Services	36,244 (15%)	205,790 (85%)	242,240
Xcel	Miles of Mains	738 (7.5%)	9,080.7 (92.3%)	9,840
	# of Services	4,281 (0.9%)	454,937 (97.7%)	465,551

Table 5. Total Leaks and Hazardous Leaks Eliminated/Repaired During 2024

Utility	Total Mains	Hazardous Mains	Total Services	Hazardous Services	Unaccounted for Gas as % of Total Consumption
CPE	309	209	7,197	3,461	1.21%
MERC	67	9	1,095	14	1.144%
Xcel	284	97	1,603	515	1.2%

*Leaks from natural or human damages, failures, or corrosion.

Data were also shared by utilities as required in the October 28, 2024, gas IRP Order under comprehensive IRP requirements paragraph

> 52, CenterPoint, MERC, and Xcel must report methane emissions from natural gas distribution system operations using available reporting protocols in the natural gas integrated resource plan until a system specific leakage estimate derived from measured leakage from the utility distribution system is available. Within 12 months of the date of this order, each utility shall file a report including the capital and O&M costs of procedures for system specific leakage rates measurements and a description of their current practices.

Xcel & Methane Leakage Detection

Xcel conducts compliance surveys to detect all types of leaks; these are done every three years per federal guidance in 49 Code of Federal Regulations ("CFR") Part 192. Xcel also estimates methane emissions per CFR Title 40-Protection of the Environment, Chapter I-Environmental Protection Agency ("EPA"), SubChapter C-Air Programs, Part 98-Mandatory Greenhouse Gas Report, collectively referred to as 40 CFR Part 98.

Recently, the Commission approved Xcel's NGIA Advanced Methane Leakage Detection (AMLD) pilot, including a single mobile detection unit.[56] Xcel's AMLD NGIA pilot begins in 2026 and will conduct super-emitter surveys to find the highest-emitting methane leaks. These surveys will be in addition to compliance surveys. Xcel's most recent gas rate case listed two additional, to NGIA, leak detection units.[57]Using data from its Colorado service territory, Table 6 shows Xcel's estimated costs for Minnesota.

[56] Xcel NGIA Order, docket no. 23-518, issued May 16, 2025

[57] Xcel gas rate case docket no. 25-356 Berger testimony at 56

Table 6. Estimated costs for MN super emitter threshold survey

1st year capital cost	Annual O&M cost	Annual capital cost
$1,800,000	$526,000	$1,200,000*

*Cost to purchase four additional AMLD units. Costs will increase if repairs are needed.

CPE & Methane Leakage Detection

CPE has AMLD via the Picarro mobile unit though the utility did not report the number of units it uses. CPE conducts compliance surveys for leaks every three years per federal guidance in 49 CFR Part 192. More, technicians walk areas with leaks detected by Picarro or not able to be patrolled by Picarro. See cost in Table 7.

Table 7. CPE AMLD spending

	2020*	2021	2022	2023	2024
O&M	$2,442,292	$2,627,341	$2,592,477	$2,874,658	$2,960,371
Capital	$3,070,343	$123,915	$195,271	$194,805	$127,025

*2020 capital expenditures include $3,060,343 for Picarro Surveyor equipment.

MERC & Methane Leakage Detection

MERC estimates methane emissions per CFR, Title 40-Protection of the Environment, Chapter I-EPA, SubChapter C-Air Programs, Part 98-Mandatory Greenhouse Gas Report, collectively referred to as 40 CFR Part 98. MERC also conducts surveys to detect leaks, despite not measuring those leaks. MERC estimated cost of an AMLD program with three leak detection vehicles (Table 8).

Table 8. Estimated costs for MERC AMLD

Annual O&M cost	Annual capital cost
$2,100,000	$2,250,000

To Staff, these leak data and the costs associated with leak data collection, e.g., approximately $1million capital cost for each AMLD unit, give an estimated cost to provide the necessary data and the magnitude of emissions that would be affected if the Commission applied regulatory costs to methane leaks on utilities' own pipes.

B. Commission decision

To Staff, it seems possible to collect data on scope one emissions and to apply the regulatory cost of GHG emissions determined here to the data collected. Commenters recommended applying costs of future regulations to upstream producers and some commenters, to end users as well. Commenters made one additional recommendation on this topic (**Decision Option 14**) which would instead allow utilities to determine to which emissions to apply regulatory costs. Thus, the questions the Commission may choose to take up are,

- What is the likelihood of future regulation would impose a cost on utilities to regulate each different scope of emissions?

- What is the magnitude of each scope of emissions?
- What is the cost of detecting those emissions or for additional AMLD?

VII. Start Date

The utilities recommended 2030 as the effective date for regulatory costs. Xcel selected 2030 as it is the midpoint in the data series on which they base their recommended regulatory upper bound. CPE also recommended 2030 citing the 2028 presidential election as well as the IMF paper on which the $75 cost regulatory cost of carbon was based as this paper found that "a carbon floor price of $75 per metric ton of CO_2 by 2030 for high income nations would be sufficient to keep global warming below 2.0^{o}C."[58]

Staff was unclear which effective date the Department would prefer so made a permissible ex parte communication. The Department was still formulating a response at the time of filing these briefing papers. The Commission may ask the Department at the agenda meeting.

VIII. **Timing**

The Department recommended allowing the current regulatory cost of carbon value (docket no. 07-1199) to dictate which values utilities use in their gas IRPs. To this extent, the values as established by Order issued December 2023 would be used by Xcel. Then, CPE and MERC would use values that will be established by current open proceeding in Docket no. 07-1199.

Conversely, CPE expected the instant proceeding to establish values for all utilities to use in their gas IRPs, per the Commission's August 25, 2025 notice in this docket where the Commission asked, "Are the values established for Minn. Stat. § 216H.06 and last approved in Docket No. E999/CI-07-1199 in the Commission's December 19, 2023 Order appropriate for use in Xcel Energy, CenterPoint Energy, and Minnesota Energy Resource Corporation's upcoming IRPs? If the current values established in the instant docket are not appropriate, what data source and update timeframe should be used for the regulatory cost of GHG emissions values for natural gas IRPs?"

Thus, CPE felt that if CPE and MERC were required to use values established in the *next* regulatory cost proceeding, CPE would not have had the opportunity to weigh in as the values for the *next* regulatory cost proceeding are being determined right now- the comment period closed on November 7th. Therefore, when the Department suggested in its October 31, 2025, comments that CPE and MERC use values from the *next* regulatory cost proceeding, there were only seven days remaining to comment.

[58] CPE initial at 5 referencing Jean Chateau, Florence Jaumotte, and Gregor Schwerhoff, Economic and Environmental Benefits from International Cooperation on Climate Policies, International Monetary Fund Department Paper (March 17, 2022), available at https://www.imf.org/en/Publications/Departmental-Papers-PolicyPapers/Issues/2022/03/16/Economic-and-Environmental-Benefits-from-International-Cooperation-on-ClimatePolicies-511562.

CPE recommended applying the regulatory cost of carbon decided in this proceeding to Xcel's, CPE's, and MERC's initial IRPs. CPE further recommended that the Executive Secretary be given authority to open a comment period to further align regulatory costs and methods across the three gas utilities and to increase understanding on this topic.[59]

A. Commission decision

Staff sees that the framing of the August 25, 2025, notice questions could have been understood to refer to the values decided specifically in the December 19, 2023 Order or whatever value would be decided in docket no. 07-1199, nearest to the time a utility did its gas IRP analyses. Such ambiguity may have set unintended expectations for utilities.

Selecting which value to use from docket no. 07-1199 may be difficult because as shown in Table 1, reproduced below, in part, the filings and Orders on the regulatory cost of carbon do not follow a regular cadence. If the Commission wanted to instruct utilities on which value to use from docket no. 07-1199, it could consider naming a cut-off date or giving other detailed instruction, though this degree of prescription seems unwieldy. Alternatively, the Commission may allow the utility to select and use "the best information currently available" at the time of their analyses.[60]

Table 1. in part, Recent dates for regulatory cost of carbon orders for electric IRPs

Dept. & MPCA Notice Issue Date	**Order Issue Date**	**Lower Bound** in $ /ton for CO_2	**Upper Bound** in $ /ton for CO_2	**Effective Year to apply costs in resource planning**
August 22, 2017	June 11, 2018	5	25	2025
July 9, 2019	Sept. 30, 2020	5	25	2025
June 30, 2022	Dec. 19, 2023	5	75	2028

Electric IRPs apply the regulatory cost of carbon, using the most recently approved values, shown below for the most recent years (Table 9). To Staff, there does not appear to have been issues coordinating when the regulatory cost Order comes out and the utility using the most recent value, even when there are only a few months between the two. Or, even if a utility uses an older vintage, like in GRE's case, presumably indicating the utility had already conducted its analyses when a new value was ordered. In this case, if needed, a request could be made for a utility to re-run an analysis with update values.

Table 9. Recent electric utility IRPs and regulatory cost order referenced

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[59] CPE replies at 4

[60] As stated in paragraph 2 of the comprehensive gas IRP requirements accompanying the Commission's October 28, 2024 Order in Docket Nos. G008, G002, G011/CI-23-117; G999/CI-21-565

Utility	Docket No.	Utility Initial Filing	Order referenced
Xcel[61]	24-67	Feb. 1, 2024	Dec 19, 2023
Minnesota Power[62]	25-127	March 3, 2025	Dec 19, 2023
GRE[63]	22-75	March 31, 2023	Sept. 30, 2020
Otter Tail Power[64]	21-339	Sept. 1, 2021	Sept. 30, 2020
Xcel[65]	19-368	July 1, 2019	June 11, 2018

IX. Conclusion

The Commission's October 28, 2024, Order had a set of comprehensive gas IRP requirements which included this paragraph, under the section Objectives and Scope:

> 2, The Commission finds that the objective of integrated resource planning for natural gas utilities is to determine, based on the best information currently available, the mix of energy resources that best protects ratepayer and public interests; maintains safe, reliable, and affordable service; and advances state policy moving forward.

First, this objective highlights the importance of <u>choosing some regulatory cost value now</u>. Choosing a value now will allow Xcel to proceed with the development of its gas IRP for submission by July 1 of this year. In fact, in this same docket 07-1199 the Department recognized that at times, we just need a value in place.[66] Indeed, the Department filed a letter recognizing the difficulty and "magnitude" of establishing the a value for the regulatory cost as well as the importance of getting a value established so that that value could be put into place when the utility needed it. Staff believes the Department's early logic in this matter could apply to gas IRPs at present. The Commission can put a value in place now for use in upcoming IRPs.

Staff takes the position that the value chosen:

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[61] Xcel Energy February 1, 2024 2024-2040 Upper Midwest Resource Plan Docket No. E002/RP-24-67

[62] Minnesota Power's 2025-2039 Integrated Resource Plan, March 3, 2025, docket no. 25-127, at 43

[63] Great River Energy 2023-2037 IRP Docket No. ET-2/RP-22-75 March 31, 2023 at 29, "For these sensitivities, GRE includes … Regulatory Cost of Carbon values determined in Minnesota Docket Nos. CI-07-1199 and DI-19-406 under Minn. Statute 216H.06 for years 2025-37." Note, Order issued in this docket June 11, 2024, acknowledged the Department claimed that GRE failed to properly incorporate regulatory costs into its model at 17. The Commission required a modeling compliance filing within one year. See Dept's August 8, 2023, comments at 36.

[64] Otter Tail Power Sept 1, 2021, Docket No. E017/RP-21-339 Appendix A: Plan Cross Reference at 5

[65] Xcel Energy 2020-2034 Upper Midwest Resource Plan docket no. E002/RP-19-368, July 1, 2019, Appendix A: Compliance Matrix at 5

[66] Department of Commerce letter received September 10, 2007 in docket no. E999/CI-07-1199.

<u>Is a starting point</u>. Staff emphasizes that the gas IRP process is new for this Commission and for utilities; thus, initial IRPs and associated components may not be "perfect." Relevant words may be found in the first Order in docket no. 07-1199, "The Commission acknowledges that all forecasts entail a degree of doubt. This fact, however, is only tangentially relevant to the Commission's decision. The future is uncertain. The need to plan for the future is not. The degree of uncertainty regarding future CO2 regulation and future technology makes the task of estimating regulatory costs more difficult; it does not make the task any less necessary."[67]

<u>Is intended to be modified</u>. In establishing the gas IRP process the Commission was clear, "The Commission must emphasize that gas integrated resource planning is an iterative process."[68]

More, following the Department's letter when docket no. 07-1199 was opened, beyond establishing an interim value, the Department recommended opening a separate proceeding to allow for additional discussion and refinement of the value. Accordingly, as additional insights are gained about the IRP process in general and from Xcel's first IRP in particular the regulatory cost value could be fine-tuned. As such, the Commission's order following the Department letter advocating for first setting an interim value, then yielded the establishment of a broader range of values for carbon.[69]

Last, Table 1 showed that the regulatory cost of carbon has changed multiple times since the proceeding opened in 2007.

<u>Is one of many data points.</u> Per the Commission's most recent Order in 07-1199, the Commission's requirement to include certain scenarios in an IRP filing need not preclude the inclusion of *additional* scenarios.[70] As such, a utility could include additional regulatory costs.

<u>Is simple and balanced.</u> The Commission has often found in favor of a simpler methodology, as opposed to an overly complicated method that might only offer marginal gains in accuracy.[71] Indeed, choosing a simpler path forward would allow a utility to spend equivalent amounts of time on other aspects of its gas IRP, thus balancing the objectives stated in ordering paragraph 2, above, a resource plan that is: safe, reliable, affordable, and advances state policy, including

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[67] Order establishing estimate of future carbon dioxide regulation costs, December 21, 2007, docket no. E-999/CI-07-1199 at 5

[68] Order October 28, 2024 in docket nos. G-008,G-002, G-011/CI-23-117 and G-999/CI-21-565, quoted text at 3, discussion at 3-4

[69] Order establishing estimate of future carbon dioxide regulation costs, December 21, 2007, docket no. E-999/CI-07-1199

[70] Order Addressing Environmental and Regulatory Costs, December 19, 2023 in 07-1199 at 13

[71] See for example, Order Addressing Environmental and Regulatory Costs, December 19, 2023 in 07-1199 at 12 in which the Commission declined "to add to the complexity with shifting regulatory cost values" by setting the lower bound of regulatory costs equal to the cost of tradable renewable energy credits.

environmental objectives like greenhouse gas emissions reductions.

A. The following decisions are before the Commission:

First, Staff explained above that it would be beneficial to the IRP process, specifically Xcel's July 2026 filing, to determine the values utilities will use to estimate the regulatory costs of GHG emissions in their gas IRPs. The Commission can select estimates to use for regulatory cost of

- Upstream methane emissions (**Decision Options 5-10)** and/or
- End-use carbon dioxide emissions (**Decision Options 11-13)**

Second, the Commission may decide which data sources are appropriate for the regulatory cost of GHG emissions values in gas IRPs. Specifically, should utilities apply regulatory cost values established elsewhere,

- For electric generation in docket no. 07-1199 (**Decision Option 3**)?
- From EPA RIAs for the crude oil and natural gas sector (**Decision Options 1-2**)?

to values measured for upstream methane and/or end use carbon dioxide?

More, does the Commission have enough information to choose an "evergreen" source of data now (**Decision Options 1-3**) or would additional information be useful? For example, a Minnesota-specific study on regulatory costs. To this extent the Commission may decline to select an "evergreen" source of data at this time (**Decision Option 4**).

Third, to Staff, it seems possible to collect data on all scope one emissions and to apply the regulatory cost of GHG emissions to those data. Commenters would apply costs of future regulations to upstream producers (**Decision Options 5-10)** and some, to end uses as well (**Decision Options 11-13)**. Thus, the Commission may choose to decide on the likelihood that future regulation will impose a cost on utilities for different emission scopes. If the Commission finds it has sufficient information to make this decision, it may establish the scope to which costs are applied. If not, it may allow utilities to decide this when conducting their analyses and learn once an actual IRP is in front of the Commission **(Decision Option 14)**.

Fourth, commenters offered only 2030 as the effective date for regulatory costs to be included in gas utilities IRP (**Decision Option 15**). The Commission may find this date appropriate or select another date. However, some date may be necessary for utilities' analyses. Like other decisions, the Commission may choose a date now or leave that to utilities.

Last, Staff advocates for utilities to use the most current data available in their gas IRPs, following the objective above. Staff understands CPE's desire to participate in the determination of regulatory costs that will be included in their IRP. However, Staff is not responsible for process in docket no. 07-1199 and defers to the Department of Commerce and MPCA about extending the comment period on the current open proceeding establishing the cost of carbon so that those utilities impacted, who may not have been tracking those proceedings, could weigh in. The Commission can consider which regulatory costs utilities use in their gas IRPs, based on the date each gas utility will file its first gas IRP (**Decision Options 16-19**). If more information is needed more broadly, further comment periods could be opened (**Decision Option 20),** or comment periods could be opened specifically to comment on timing (**Decision Option 21A)** and / or alignment across gas and electric costs **(Decision Option 21B).**

Staff ends with the Commission's statement emphasizing that not every decision need be made today and that what is most important is establishing some value for the regulatory cost of carbon for gas utilities to use in their initial gas IRPs: "The Commission is hesitant to overburden gas utilities with overly prescriptive content and procedural requirements before a single Gas IRP has been filed here."[72]

DECISION OPTIONS

Staff Note: As Xcel, CPE, and MERC will file their first gas IRPs, one each year, in 2026, 2027, and 2028, different regulatory costs could apply to different utilities.

- *The Commission may decide that a certain proceeding will be the source for the regulatory cost of GHG used in gas IRPs by selecting from Decision Options 1-3, potentially with 18.*

- *Whether the Commission does or does not select a source for regulatory cost values, it may still select specific values to use in gas utilities' IRPs. Those options are found in Decision Options 5-13, potentially with 19.*

To decide if utilities use the same or different values in their gas IRPs, the Commission may choose either pathway:

- *With Decision Options 16 & 17, the Commission may choose to have Xcel use one set of values, decided now, while CPE and MERC use a different set of values to be determined the proceeding(s) selected using Decision Options 1-3.*
- *All utilities will use the same values in their gas IRPs by selecting Decision Option 18 or 19.*

Data Source

1. Require utilities, in gas integrated resource planning, to base estimates of the regulatory cost of carbon for natural gas supply resources on U.S. Environmental Protection Agency (EPA) rules to reduce methane from oil and gas (O&G) operations as found most recently at (https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-operations/epas-final-rule-reduce-methane-and-other). (Xcel)

2. Require utilities to use in gas integrated resource planning the natural gas environmental compliance factor applied through the Energy Conservation and Optimization (ECO)

[72] Order October 28, 2024 in docket nos. G-008,G-002, G-011/CI-23-117 and G-999/CI-21-565, quoted text at 3

framework. (Department)

3. Determine that the values established for Minn. Stat. § 216H.06 and last approved in Docket No. E999/CI-07- 1199 in the Commission's December 2023 Regulatory Costs Order are appropriate in gas IRP proceedings. Require utilities to use in gas integrated resource planning the current values as established in Docket 07-1199. (Department, Fresh Energy, MCEA, and Sierra Club)

4. Decline to adopt a source data for GHG emissions in gas IRPs at this time. (Staff, providing alternative)

Values

Methane

5. Require utilities to use in gas integrated resource planning a lower regulatory cost of carbon value of $0 / MMT CO2e. (CPE; Xcel; MERC)

6. Reject CPE's and Xcel's proposal to use a lower regulatory cost of carbon value of $0 (Department)

7. Require utilities to use in gas integrated resource planning an upper regulatory cost of carbon value of $13 / MMT CO2e. (Xcel; CPE; MERC)

8. Reject Xcel's proposal to use the higher regulatory cost of greenhouse emissions value of $13. (Department)

9. Require utilities to use in gas integrated resource planning a range of $9 to $13 per ton of CO2e emissions to plan for the regulation of upstream methane emissions. (Fresh Energy, MCEA, and Sierra Club)

10. Require utilities to use in gas integrated resource planning the natural gas environmental compliance factor applied through the Energy Conservation and Optimization (ECO) framework – currently 1.4% of the commodity cost of natural gas for 2024-2045. (Department)

Carbon Dioxide

11. Require utilities to use in gas integrated resource planning a range of $5 to $75 per ton of CO2e emissions to plan for regulation of end-use emissions. (Fresh Energy, MCEA, and Sierra Club)

12. Require utilities to use in gas integrated resource planning a range of -$50 to $50 for the regulatory cost of carbon. (LIUNA)

13. Decline to assign a regulatory cost of carbon at this time for gas utility planning (LIUNA preferred)

Emissions Scope

14. Allow CenterPoint Energy, Xcel Energy, and MERC to develop their initial gas IRPs using existing guidance on the application of the regulatory cost of carbon. (CPE)

Start Date

15. Require utilities to use in gas integrated resource planning the effective date for regulatory costs of 2030 (CPE; Xcel; MERC).

Timing

16. Xcel shall use the values established for Minn. Stat. § 216H.06 and last approved in Docket No. E999/CI-07-1199 in the Commission's December 2023 Regulatory Costs Order. (Department)

AND

17. CenterPoint Energy shall use in its gas IRP due on July 1, 2027, and MERC shall use in its gas IRP due on July 1, 2028, values to be determined after the Agencies seek feedback in Dockets 25-345 and 07-1199 based on the Commission's September 2025 Notice, and the Agencies provide their analysis and recommendations to the Commission; and after the Commission makes its determinations on the regulatory costs of greenhouse gas emissions during the proceedings in Docket 07-1199. (Department with Staff modification to language)

OR

18. In their gas IRPs, Xcel, CPE, and MERC shall use the values established for Minn. Stat. § 216H.06 and last approved in Docket No. E999/CI-07-1199 in the Commission's December 2023 Regulatory Costs Order. (CPE)

OR

19. Xcel, CPE, and MERC shall use in their gas IRPs the values determined for the regulatory cost of carbon in this Order until further Notice. (Staff alternative)

Further Decision-Making

20. Delegate authority to the Executive Secretary to open further comment periods to establish guidance related to the regulatory cost of greenhouse gas emissions (Staff).

21. Delegate authority to the Executive Secretary to issue a notice of comment period before the submission of the gas utilities' second IRPs on the following:

    A. The need to further harmonize the application of the regulatory cost of carbon across gas utilities' IRPs.

    B. The need to standardize regulatory cost values across gas and electric utilities. (CPE)

Appendix

GHG Emissions reported by utilities as requested by Dept. Showing Total from Subpart NN and Subpart W reporting in metric tons of CO2e unless indicated

Year	**CPE (NN)***	**CPE (W)**	**MERC (NN)***	**MERC (W)**	**Xcel (NN)**	**Xcel (W)**
2021	7,599,163.60	67,815.30	2,156,967	26,666	6,366,824	57,907
2022	8,530,474.20	68,220.60	2,306,474	25,806	5,883,715	57,141
2023	7,486,835.50	67,972.50	2,032,267	25,304	6,077,150	53,744
2024	7,262,130.50	75,530.20	1,753,549	28,735	5,967,462	60,414

*Reported as metric tons CO_2.

Subpart NN is for suppliers of natural gas to report of CO2 emissions that would result from the complete combustion or oxidation of the annual volumes of natural gas provided to end users on their distribution systems LESS volumes that are stored, reported by other large customers at > 460,00Mscf/year natural gas, and transmission pipes or other LDCs.

Subpart W is a report for petroleum and natural gas systems. These systems must report emissions from distinct leak categories.

Customer Gas Sales in Dekatherms reported by utilities as requested by Dept. Shown for some customers- Residential (R) and Electricity Generation-Transport type (Gen).

Year	CPE- R (Mcf)	CPE- Gen (Mcf)	MERC-R	MERC- Gen	Xcel-R	Xcel- Gen
2021	68,242,993	16054043.5	17,723,420	7,044,871	35,286,911	38,287,916
2022	78,312,891	15035698.4	21,170,046	6,241,758	41,156,174	20,192,049
2023	67,154,559	25598452.3	17,490,873	7,834,762	35,470,580	30,310,131
2024	63,992,394	27853561.4	16,834,543	11,167,018	33,038,318	40,795,821

* Note, CPE provided the information directly but also referenced Docket no. YR-19 where the requested information is already filed annually. Staff located the data using the tab labeled "SalesByCategory_Small." However, data are reported in Mcf, not dekatherms.