MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	September 14, 2023		Agenda Item 1**
Company	All Electric Utilities		
Docket No.	E999/CI-07-1199; E999/DI-22-236		
	In the Matter of Establishing an Estimate of the Costs of Future Carbon Dioxide Regulation on Electricity Generation Under Minnesota Statutes § 216H.06		
Issues	How should the Commission update the Cost of Future Carbon Dioxide (CO_2) Regulation on Electricity Generation for the years 2023-2024?		
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The attached materials are work papers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

Relevant Documents	**Date**
The Agencies' Analysis and Recommendations	January 5, 2023
Clean Energy Organizations Initial Comments	July 13, 2023
The Agencies Initial Comments	July 14, 2023
Xcel Energy Initial Comments	July 14, 2023
Great River Energy Initial Comments	July 14, 2023
Center for Energy and Environment Initial Comments	July 14, 2023
Otter Tail Power Initial Comments	July 14, 2023
Minnesota Power Initial Comments	July 14, 2023
Xcel Energy Reply Comments	August 4, 2023
Minnesota Power Reply Comments	August 4, 2023
Clean Energy Organizations Reply Comments	August 4, 2023

ACRONYMNS

CAA: "Clean Air Act."

CFS: "Carbon Free Standard." Requires Minnesota electric utilities to generate or procure 100% of their total retail electric sales in Minnesota with carbon-free energy resources. Established by Minnesota Session Laws 2023, Chapter 7, section 10 and signed into law on February 7th, 2023.

CH_4: "Methane"

CO_2: "Carbon dioxide."

FSCC: "Federal Social Cost of Carbon."

GHG: "Greenhouse Gas."

IWG: "Interagency Working Group." President Biden reestablished the IWG after it had been disbanded by the Trump Administration, and directed the IWG to publish interim estimates for the social cost of carbon, nitrous oxide, and methane.

N_2O: "Nitrous oxide."

NO_X: "Nitrogen oxides."

NSPS: "New Source Performance Standards"

$PM_{2.5}$: Particulate atter that have a diameter of less than 2.5 micrometers.

PVRR: "Present value revenue requirements." The costs associated with an integrated resource plan, but does not include the regulatory cost of carbon or externality costs.

PVSC: "Present value of societal cost." The net present value of all of an integrated resource plan's costs, including the regulatory cost of carbon and all externality costs.

RGGI: "Regional Greenhouse Gas Initiative."

SC-GHG: "Social Cost of Greenhouse Gases." Used in reference to the EPA's social costs for carbon dioxide, methane, and nitrous oxide.

SO_2: "Sulfur dioxide."

WCI: "Western Climate Initiative."

STATEMENT OF ISSUES

How should the Commission update the Cost of Future Carbon Dioxide (CO_2) Regulation on Electricity Generation for the years 2023-2024?

RELEVANT STATUTES

Minn. Stat. § 216H.06 directs the Commission to "establish an estimate of the likely range of costs of future carbon dioxide [CO_2] regulation on electricity generation." Furthermore, the Commission shall periodically update that estimate, following informal proceedings conducted by the Department of Commerce and Minnesota Pollution Control Agency (collectively, "the Agencies"). The CO_2 regulatory costs "must be used in all electricity generation resource acquisition proceedings," which most commonly appear in utilities' integrated resource plan (IRP) proceedings.

The Commission's IRP process is governed by Minn. Stat. § 216B.2422. Environmental externality costs – which reflect the social damage of pollution – are required under Minn. Stat. § 216B.2422, subd. 3., which states:

> (a) The Commission shall, to the extent practicable, quantify and establish a range of environmental costs associated with each method of electricity generation. A utility shall use the values established by the Commission in conjunction with other external factors, including socioeconomic costs, when evaluating and selecting resource options in all proceedings before the Commission, including resource plan and certificate of need proceedings.

On February 7, 2023, Governor Walz signed Minnesota Session Laws 2023, Chapter 7, section 18, which revised Minn. Stat. § 216B.2422, subd. 3 to require the Commission to "provisionally adopt and apply" the draft cost of greenhouse gas emissions valuations[1] (social cost of greenhouse gases or "SC-GHG"), as presented in the U.S. Environmental Protection Agency's (EPA) *External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates incorporating Recent Scientific Advances*.[2] Section 18 also requires the Commission to adopt the final version of the EPA report when it becomes available. Additionally, on a going-forward basis, the Commission must adopt the Federal Interagency Working Group's (IWG)[3] SC-GHG values if they ever exceed the estimates adopted by the Commission:

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[1] The EPA's draft report included a social cost of Carbon (CO_2), Methane (CH_4), and Nitrous Oxide (N_20).

[2] See Attachment 1.

[3] In 2009, the Obama Administration convened an interagency working group (IWG) to develop a set of estimates for the social cost of greenhouse gases (SC-GHG). The IWG developed a methodology and published a set of four social cost of carbon estimates which measured the global value of carbon dioxide reductions and are used in regulatory analysis. In January of 2021, President Biden reestablished the IWG after it had been disbanded by the

> (b) The commission shall provisionally adopt and apply the draft cost of greenhouse gas emissions valuations presented in the United States Environmental Protection Agency's EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, released in September 2022, including the time horizon, global estimates of damages, and the full range of discount rates from 2.5 to 1.5 percent, with two percent as the central estimate. The commission shall adopt the estimates contained in the final version of the external review draft report when it becomes available.
>
> (c) If, at any time, the estimates adopted by the commission under paragraph (a) are exceeded by estimates released by the federal Interagency Working Group on the Social Cost of Greenhouse Gases or its successors, the commission shall adopt the working group estimates.

Staff notes that using discount rates of 2.5%, 2%, and 1.5% translates to \$120, \$190, and \$340 per metric ton of CO_2 in 2020, respectively.

Additionally, Minnesota Session Laws 2023, Chapter 7, section 10 (the Carbon-Free Standard, or CFS) requires Minnesota utilities to, among other things, generate or procure the following percentages of total retail electric sales in Minnesota with carbon-free energy resources:

- 80% by 2030 for investor-owned electric utilities and 60% for consumer-owned electric utilities;
- 90% by 2035 for all electric utilities; and
- 100% by 2040 for all electric utilities.

RELATIONSHIP TO THE COMMISSION'S EXTERNALITIES DOCKET

In January 2018, the Commission issued an order in Docket No. 14-643 (the Externalities Docket) adopting a previous version of the federal social cost of carbon (FSCC),[4] with some modified assumptions. The Commission's order followed a contested case proceeding to update the original externality values established in 1997. Additional context is provided below.

On October 9, 2013, several environmental advocacy organizations filed a motion requesting that the Commission update the cost values for emissions of CO_2, NO_X, and SO_2 and establish a cost value for emissions of fine particulate matter ($PM_{2.5}$). The organizations recommended that the Commission adopt the then-current FSCC as the cost value for CO_2 and retain an

Trump Administration and directed the IWG to publish interim estimates for the social cost of carbon, nitrous oxide, and methane.

[4] Staff notes that the IWG's draft report on the SC-GHG includes new values for the FSCC.

independent expert to analyze the costs of the other three pollutants. On October 15, 2014, the Commission issued a *Notice and Order for Hearing* referring the investigation to the Office of Administrative Hearings for a contested case and directed parties to address (1) whether the FSCC is reasonable and the best available measure to determine the environmental cost of CO_2 and (2) the appropriate values for $PM_{2.5}$, SO_2, and NO_X.

On January 3, 2018, the Commission issued its Externalities Order and updated its range of environmental costs under Minn. Stat. §216B.2422, subd. 3. For CO_2, the Commission determined that the FSCC represented "the best available measure to determine a range of costs associated with the emission of carbon dioxide from power plants."[5] However, the Commission made some adjustments to the economic assumptions, while keeping others, for use in Minnesota proceedings. Below, staff underlined three key assumptions in Order Point 1.[6] These pertain to (1) CO_2 having a global geographic scope (as opposed to being confined to state boundaries); (2) the time horizon for modeling social damages; and (3) the discount rate.

> 1. The Commission hereby quantifies and establishes the range of environmental cost of carbon dioxide emissions associated with electricity generation as follows:
>
> - The low end of the range shall reflect the <u>global damage</u> of the last (marginal) short ton emitted, calculated <u>through the year 2100</u>, with a <u>5.0% discount rate</u>.
>
> - The high end of the range shall reflect the <u>global damage</u> of the last (marginal) short ton emitted, calculated <u>through the year 2300</u>, with a <u>3.0% discount rate</u>.[7]

Staff notes that the legislature's revision to Minn. Stat. §216B.2422, subd. 3 also uses a FSCC. The legislature's preferred assumptions use:

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[5] January 3, 2018 Commission Order, Docket No. 14-643, p.5.

[6] At the July 27, 2017, Commission hearing, the Commission adopted two sets of economic framing assumptions for its range of values for CO_2, which are described by Order Point 1. The Commission had 2020 emission year values for those two sets of framing assumptions in hand at the time it adopted them, but not other emission years. Accordingly, the Commission verbally ordered the Utilities to make a compliance filing providing emission year values for additional years. In an August 3, 2017, compliance filing, the prepared values for 2020 and 2050, which were derived from conducting runs of the full suite of integrated assessment models consistent with the July 2015 IWG Technical Support Document. Other values were derived from a linear interpolation/extrapolation from the model-based values.

[7] Staff notes that the record in Docket No. 14-643 discussed the fact that CO_2 can remain in the atmosphere for hundreds of years, so the IWG calculated the damages from an emission in a given year to include the damages through 2300; however, some parties (including the Utilities) criticized the IWG for extending the models that far into the future, due to the level of speculation involved. The same parties pointed out the Commission adopted an estimate based on a time horizon of 100 years when it determined the social cost of carbon in 1997. The ALJ recommended an extrapolation to the year 2200.

1. IWG's time horizon (which are the same as the high bound of the Commission's values);
2. a global geographic scope (which is the same in the low and high bounds in the Commission's values), and
3. the full range of discount rates from 2.5% to 1.5%, with 2% as the central estimate (which are lower than the Commission's low end of the range).

Table 1 below compares the two sets of economic assumptions:

Table 1: Commission and IWG Economic Assumptions

Variable	Commission	IWG
Geographic Scope	Global	Global
Time horizon (Yr)	2300 (high) to 2100 (low)	2300
Discount rate	3% (high) to 5% (low)	1.5% (high) to 2.5% (low)
Units	Short ton	Metric ton
Range in Year 2023	$11.22 to $52.43/short ton	$120 to $340/metric ton

Staff notes that the discount rate used during the externalities proceeding was among the most impactful variables to the resulting values, which is in part due to the length of the modeled time horizon being discounted. A lower discount rate yields a larger discounted present value, while a higher discount rate yields a smaller discounted present value. As an example, the present value in 2020 of $100 of damage occurring in 2100 is $13.87 using an annual discount rate of 2.5%. Using an annual discount rate of 5%, it is $2.02. Ultimately, the weight given to the costs and benefits to future generations is a policy decision, but the discount rate assumption is a major contributor to the calculated values.

BACKGROUND

The Commission first established CO_2 regulatory costs in a December 2007 Order in Docket No. E999/CI-07-1199, and they have been updated roughly every other year since (seven times in total). The table below shows historical ranges (in $ per short ton) and threshold planning years, starting with the most recent order on September 30, 2020, and ending with the inaugural December 2007 Order. As shown, the current range is $5 to $25 per short ton beginning in 2025.

Table 2: Regulatory Cost Values (2008 – present)

Order (years)	Range ($ per ton)	Threshold Planning Year
2020-present	$5 - $25	2025
2018-2019	$5 - $25	2025
2016-2017	$9 - $34	2022
2014-2015	$9 - $34	2019
2012-2013	$9 - $34	2017
2011-2012	$4 - $34	2012
2009-2010	$9 - $34	2010
2008	$4 - $30	2012

This docket is unique from a procedural standpoint because the statute bifurcates the process of updating the regulatory costs into two separate proceedings. First, there is a Department Investigation (DI) docket, in which the Agencies prepare a report of "Analysis and Recommendations" after receiving comments from parties. A subsequent Commission Investigation (CI), which is the same docket each time (Docket No. 07-1199), commences once the Agencies file its report, and the Commission subsequently seeks comment on whether the Agencies' recommendations are reasonable.

Importantly, CO_2 regulatory costs are different than the Commission's environmental externalities, which are required under a different statute, are not updated regularly, and reflect different types of costs.

- **Regulatory Costs:** CO_2 regulatory costs reflect an estimate of likely future carbon policy that is expected to impact ratepayers.

- **Environmental Externalities (Social Costs):** Environmental externalities reflect the impact of pollution from electric generation on society as a whole.

From a capacity expansion modeling perspective, the notable difference between the two types of carbon costs is that only regulatory costs are a direct cost to CO_2-emitting units. Similar to fuel costs, CO_2 regulatory costs are incorporated into the cost of dispatch. Externalities, on the other hand, are added to the model *after* capacity expansion plans are selected. In other words, externalities impact the relative ranking of various resource plans, but not unit dispatch or resource selection. Generally speaking, this makes regulatory costs more impactful to the model's optimized expansion plan than externalities, even if externality costs are higher. Because both types of CO_2 costs are required to be used in resource planning and acquisition proceedings, the Commission's 2007 regulatory costs order established a methodology that could (a) incorporate both types of values in a single scenario while (b) avoiding the double counting of two carbon values in any given year. Over time, different orders have required different approaches to the modeling – including whether or not to require a midpoint, whether to require a specific base case scenario, how many scenarios utilities shall run, etc. – but the avoidance of double counting has remained consistent.

The Commission last updated its CO_2 regulatory costs on September 30, 2020. Order Point 2.A though 2.E of that order required utilities to run five regulatory cost/externality scenarios, which are described qualitatively in Table 3 below. Environmental externalities are included in all five scenarios, both as separate scenarios (scenarios A and B) and in the regulatory cost scenarios (scenarios C-E) prior to the year in which regulatory costs take effect.

Table 3: Modeling Scenarios

Scenarios	Before 2025		2025 and Thereafter	
	Environmental Cost	Regulatory Cost	Environmental Cost	Regulatory Cost
Low Environmental Cost	Low End	-	Low End	-
High Environmental Cost	High End	-	High End	-
Low Environmental/Regulatory Costs	Low End	-	-	$5/Ton
High Environmental/Regulatory Costs	High End	-	-	$25/Ton
Reference Case Scenario	Middle to High End	-	Middle to High End	Middle to High End

Table 4 below presents the annual values in each of the five scenarios from Order Point 2.A – 2.E. Scenarios A and B capture the externality values range. Scenarios C and D capture regulatory costs range. Scenario E is an optional scenario if utilities choose to run a midpoint as their Reference Case. (Not all utilities use this option; for example, Xcel does not run a middle value because it uses High Env./High Reg., or Scenario D, as its Reference Case.)

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Table 4: Regulatory Cost Modeling Scenarios

Year	Scenario A Low Environmental Costs ($)	Scenario B High Environmental Cost ($)	Scenario C Low Environmental / Low Regulatory Cost ($)	Scenario D High Environmental / High Regulatory Cost ($)	Scenario E* Middle Environmental / Middle Regulatory Cost ($)
2023	11.22	52.43	11.22	52.43	31.83
2024	11.69	54.55	11.69	54.55	33.12
2025	12.16	56.72	5.00	25.00	15.00
2026	12.67	58.97	5.10	25.50	15.30
2027	13.17	61.29	5.20	26.01	15.61
2028	13.7	63.67	5.31	26.53	15.92
2029	14.24	66.12	5.41	27.06	16.24
2030	14.8	68.64	5.52	27.60	16.56

*Staff notes that for Scenario E (the reference case scenario) utilities have a choice to use middle to high values for both the regulatory cost values and the environmental cost values. For this visualization, Staff used the middle environmental cost value and the middle regulatory cost value.

The Agencies' report was filed on January 5, 2023, which was prior to the passage of the CFS.[8] However, the Agencies' recommendations largely did not change as a result of the CFS. Later sections of this briefing paper will explain the Agencies' rationale and parties' responses.

Overall, the Commission's decision on this matter must, at a minimum:

1. Set the regulatory cost range and escalation factor;
2. Establish the effective date for the regulatory cost of carbon;
3. Set modeling scenarios;
4. Decide whether or not to apply the established regulatory costs to both 2023 and 2024;
5. Decide if, or how, the CFS and the EPA's draft rule should be considered with regard to the regulatory cost of carbon and related modeling scenarios; and
6. Decide how to respond to Minn. Stat. § 216B.2422, subd. 3 to require the Commission to "provisionally adopt and apply" the SC-GHG values.

AGENCIES' REPORT

For reasons to be discussed later in this section, the Agencies' January 5, 2023, report recommend that the Commission:

- raise the upper bound of the existing range from \$25 to \$30 per ton of CO_2 emitted, but keep the lower bound at \$5 per ton of CO_2 emitted;
- adopt a yearly escalation factor of 4%; and

[8] Minnesota Session Laws 2023, Chapter 7, section 10.

- keep 2025 as the threshold year for which these values should begin to be applied.

The three bullet points are all incorporated into Decision Option 1.

Additionally, the Agencies recommended directing utilities continue using the modeling scenarios established in the September 2020 Order.

This recommendation is represented in Decision Option 5.

The Agencies' report addresses four primary issues: 1, the range of likely regulatory cost; 2, date of application; 3, the modeling scenarios; and 4, whether the established values should be applied to proceedings in 2023 only, or both 2023 and 2024. Prior to issuing its Analysis and Recommendations, the Agencies received comments from:

- Center for Energy and Environment (CEE)
- City of Minneapolis (Minneapolis)
- Clean Energy Organizations (CEOs)
- Community Power
- Great River Energy (GRE)
- Minnesota Power (MP)
- Otter Tail Power (OTP)
- Xcel Energy (Xcel)

There was disagreement regarding the appropriate range of likely regulatory costs. Both MP and OTP believed that the current $5-$25 per ton regulatory cost range continues to be reasonable. Minneapolis, CEOs, and Community Power argued for significant increases to the regulatory cost range citing the Paris climate agreement, federal and state policy goals to decarbonize the economy, and extreme weather events as variables that increase the likelihood of higher regulatory costs in the near future. Xcel recommended increasing the upper bound of the range from $25 to $30 per ton of CO_2 arguing that maintaining the lower bound of $5 is appropriate given the lack of federal or state regulations that put a price on carbon emissions from the electric sector. The Company believed a slight increase of the upper bound is appropriate due to rising clearing prices in existing U.S. carbon trading markets[9] and increased uncertainty in the greenhouse gas regulatory landscape, particularly in the wake of the U.S.

[9] Examples include the Western Climate Initiative (WCI) and the Regional Greenhouse Gas Initiative (RGGI). The Agencies' report states that these existing carbon market prices may be the best available proxies on which to base predictions of regulatory costs. Additionally, these carbon market prices have factored strongly in the Agencies' past recommendations for regulatory cost values.

Supreme Court decision in the *West Virginia vs. EPA* case[10] and the [then] expected updates from the EPA to rules 111(b) and 111(d).

The Agencies recommended maintaining the $5 per ton low bound of the range but increasing the upper bound of the range of likely regulatory costs from $25 to $30, stating:

> …the Agencies note that there have not been significant regulatory developments since the Commission last set these values in September 2020 to provide an objective basis for significantly altering the current cost range of $5 to $25 per ton of CO2 emissions. However, the Agencies do believe that the combination of future regulatory uncertainty and rising allowance prices in U.S. carbon markets warrants a slight expansion of the regulatory cost range and recommend an increase of the upper bound of the range from $25 to $30 per ton of CO2 emissions.[11]

The Agencies also recommended the Commission adopt a yearly escalation factor of 4% for the regulatory costs for all utilities. Currently, each utility starts with the established range of likely regulatory costs in 2025, and then escalates the values every year by some factor. The Agencies noted that in the past the Commission has not specified an escalation factor for these costs, instead allowing for utilities to use different values in their planning processes. In support of this recommendation the agencies noted:

> The market clearing allowance prices in both WCI and RGGI have had an upward trend despite their volatility. As these markets are designed to reduce the supply of allowances to help meet more aggressive decarbonization targets in the future, the equilibrium prices are expected to have an upward trend. While the compound annual growth rate in historic equilibrium market prices is sensitive to start and end years, they remain consistently higher than the Federal Reserves' long term inflation target of 2%.[12]

While there was some disagreement on when regulatory cost values should be applied,[13] the Agencies ultimately recommended that the Commission continue to use 2025 as the starting year for the application of regulatory cost values. The Agencies stated:

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[10] A Supreme Court Case that held that the EPA lacks the authority under the Clean Air Act to impose emissions gaps by shifting electricity production from higher-emitting to lower-emitting producers.

[11] Agencies' report, p.5

[12] Agencies' report, p.5

[13] The Agencies reported that commenters' views on when the regulatory cost values should be applied fell along similar lines to their views on what the values should be. Several commenters, including MP, Xcel, and the CEOs argued that 2025 continued to be a reasonable starting year of application. OTP believed that a lack of anticipated regulations indicates that 2028 would be a more reasonable year to start applying regulatory values. Both the City of Minneapolis and Community Power argued that a delay of regulatory costs to 2024 is unnecessary and should be applied as soon as possible.

> The Agencies agree with the majority of commenters that there is not sufficient objective basis for revising the current 2025 threshold year affirmed by the Commission in 2020. While GHG regulations at the federal or state level that would impose compliance costs on Minnesota electricity generators as soon as 2025 are unlikely, they cannot be entirely ruled out. All commenters seem to agree that there is significant uncertainty in the future of regulatory carbon emission costs, just as there was when the Commission ruled on this in September 2020. The Agencies believe that this uncertainty weighs in favor of keeping current decisions in place rather than overturning them.[14]

The Agencies discussed parties' comments regarding the Commission's required modeling scenarios and how parties believe regulatory and externality costs should be applied:

> Most commenters either stated that the current Commission decision about how to apply regulatory and environmental cost ranges (described above) is reasonable or did not weigh in on the issue. Only CEE, City of Minneapolis, and CEOs argued for changes in the Commission's current required planning scenarios. CEE commented fairly extensively on this issue, arguing that the Commission should not require planning scenarios with only regulatory costs and no environmental costs because the regulatory costs do not fully account for the societal damages from carbon emissions and thus do not fully internalize the externality. While CEE agrees that both regulatory and environmental costs should not be applied additively, that scenarios that include regulatory cost values but no environmental cost values, that the difference between the environmental and regulatory cost should also be included in order to fully internalize the externality. CEOs made a very similar argument, also maintaining that when regulatory costs are lower than environmental costs then in scenarios that only include regulatory costs the balance of externality values should also be applied.[15]

While the Agencies acknowledged the general economic principle that the socially-optimal outcome may be reached if the full magnitude of the externality is internalized by the utility in the decision-making process, they noted that it would not be meaningful to compare environmental costs and regulatory costs "dollar for dollar" as they are applied in different stages of the planning process.[16]

Again, the Agencies recommended no changes to the Commission's current decision for how

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[14] Agencies' report, p.6

[15] id.

[16] The Agencies elaborated, stating: "Future regulatory costs are considered as future internal costs and treated just like any other variable cost, and are therefore considered by the model when it selects units to dispatch. Externality values, however, are considered separately and applied to the suite of resources a model run selects so that externality costs are considered when ranking the cost of each plan. This method is consistent with what the costs represent – future internal costs, and externality costs. Essentially, the carbon reductions achieved through a $1 regulatory cost is very different from a $1 externality cost." – Agencies report, p.6

the established value ranges are applied to modeling scenarios, concluding:

> The Agencies think it is valuable to require utilities to provide the same basic scenarios in such proceedings, and note that the utilities and other stakeholders are not precluded from providing or requesting additional scenarios or sensitivity analyses. Importantly, the Commission's scenarios requirements are consistent with Minnesota Statutes §§ 216H.06 and 216B.2422, subd. 3, to consider future regulatory cost of carbon regulation and environmental externality values in resource planning and acquisition proceedings.[17]

Finally, the Agencies reported that all commenters agreed that it would be reasonable if the values the Commission establishes were applied to resource proceedings in both 2023 and 2024. This is represented by Decision Option 15.

SUMMARY OF PARTY RECOMMENDATIONS IN CI-07-1199

As stated previously, the Commission has several decisions to make, including:

- Setting the regulatory cost range and escalation factor;
- Establishing the effective date for the regulatory cost of carbon;
- Setting modeling scenarios;
- Applying the established regulatory costs to both 2023 and 2024;
- Deciding if, or how, the CFS and the EPA's draft rule should be considered with regard to the regulatory cost of carbon and related modeling scenarios; and
- Addressing Minn. Stat. § 216B.2422, subd. 3 to require the Commission to "provisionally adopt and apply" the SC-GHG values.

Below, Staff summarizes each parties' position on these topics:

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[17] Agencies Report, p.7

Table 5: Staff Summary of Party Positions (Part 1)

	Regulatory Cost	Threshold Planning Year	Annual Escalation Factor	Apply regulatory costs to proceedings in both 2023 and 2024?
Agencies	\$5-\$30/ton	2025	4%	Yes
CEE	\$0			
CEO	\$0-\$75/ton	2028	4%	
GRE	\$0 (preferred), or use the cost of RECs for regulatory costs			
MP	\$0 (preferred), or \$0-\$30/ton	2023 (for \$0 regulatory cost only), or 2025, or 2028 (not opposed)	Set escalation factor to equal utility inflation assumptions	
OTP	\$5-\$30/ton (not opposed)	2025 (not opposed)	4% (not opposed)	
Xcel	\$0 (preferred), or \$0-\$30/ton	2025	2%, or equal to utility inflation assumptions	

Table 6 Staff Summary of Party Positions (Part 2)

	Modeling Scenarios	Incorporating CFS and EPA Draft Rule	Application of FSCC
Agencies	Keep 5 currently used scenarios. Consider new modeling scenario that retains the balance of externality costs.	Monitor the EPA's Greenhouse Gas Power Plant Rule.	Update the Commission's Order in Docket E-999/CI-14-643 to make it consistent with current statutes.
CEE	Should the Commission set a non-zero regulatory cost, retain the balance of the statutorily required externalities.	Do not attempt to incorporate or embed the costs associated with CFS compliance within regulatory cost of carbon. Once the EPA Rule has been finalized, direct utilities to provide a description on how they plan to comply.	Require utilities to apply the provisional social cost of carbon values included in the EPA's draft report using a 2% discount rate, as summarized on Table ES 1 of page 2 of the draft report. (see Appendix 1 of this Briefing Paper) Open a comment period in this Docket, or Docket No.

			E999/CI-14-643 to consider a process to review and adopt future IWG estimates of the social cost of carbon.
CEO	Keep 4 of the 5 currently used scenarios, and retain the balance of the statutorily required externalities.	Require utilities to show how they plan to comply with the CFS and the EPA rule in their next IRPs	Did not make an explicate recommendation, but stated that the legislature has, with unprecedented specificity, instructed the Commission to adopt the full range of discount rates and subsequent FSCC values from the federal interagency working group. Minn. Stat. §216B.2422, subd.3(b) does not provide the Commission with the authority to replace environmental cost values with regulatory costs at a year of its choosing.
GRE			
MP	Should the Commission set a non-zero regulatory cost, keep 5 currently used scenarios	With the CFS in place, a regulatory cost of carbon is no longer necessary. Monitor the EPA's Greenhouse Gas Power Plant Rule	
OTP	Keep 5 currently used scenarios (not opposed)	With the CFS in place, a regulatory cost of carbon is no longer necessary. It is too early in the rule making process to assess the impact of the EPA's Greenhouse Gas Power Plant Rule	Anticipates the Commission's Order would replace the current social cost of carbon values with the EPA's values
Xcel		With the CFS in place, a regulatory cost of carbon is no longer necessary. It is too early in the rule making process to assess the impact of the EPA's Greenhouse Gas Power Plant Rule.	Recommend the draft FSCC values be used in a sensitivity analysis and be considered an externality.

PARTY COMMENTS

I. Responses to the Agencies' Report

A. The Agencies

Staff notes that the Agencies' July 14, 2023, comments in Docket No. 07-1199 respond only to the Commission's Supplemental Topics for Comment in the March 29, 2023 *Second Notice Extending Comment Period*. The Agencies did not modify their recommendations from the January 5, 2023, report, but they did make one recommendation for an additional modeling scenario.

Given the passage of the CFS, the new directives under 216B.1691 Subdivision 2 and 3,[18] and the "significant gap" between the recommended regulatory cost of carbon and the SC-GHG carbon values, the Agencies recommended the Commission consider including a model scenario that recognizes human and environmental impacts of emissions that occur in all years, even those years where a regulatory cost of carbon is applied. This is represented by Decision Option 8. The Agencies stated:

> Although a perfectly designed regulatory cost theoretically represents an economically efficient level of emissions and would optimally signal a price point at which society does not value any further reduction in climate change impacts, the Commission's decision-making may benefit from a model scenario that considers those impacts.[19]

B. Clean Energy Organizations

The CEOs recommended that the Commission adopt a regulatory cost range of $0 - $75/ton. The CEOs explained that neither the CFS nor the proposed EPA rule would fully decarbonize the power grid by 2035, which is the current goal of the Biden administration.[20] According to the CEOs, so long as utilities emit CO_2, they face risk of future additional carbon regulation. The CEOs cited several studies that predict what carbon prices would be necessary to achieve various greenhouse gas reduction goals but stated that a 2022 research paper by the International Monetary Fund (IMF) produced the most reasonable proxy for the upper cost of future carbon regulations. The IMF study estimated that carbon costs of $75/metric ton by 2030 for high-income nations would be sufficient to reduce emissions enough to keep global warming below 2.0^{o} C. Additionally, a low regulatory cost estimate of $0/ton would represent

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18 Considerations of impacts to historically undervalued communities

19 Agencies initial comments, p.7

20 White House, *Fact Sheet: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies* (April 22, 2021), [FACT SHEET: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies | The White House]

the possibility that no further carbon regulations will be put in place. Such would be the case if technological and price improvements from carbon-free energy sources drove carbon emissions reductions faster than the CFS and EPA rule, which would make additional carbon regulations unnecessary.

The CEOs recommended that 2028 be used as the threshold year for their proposed $0 - $75/ton regulatory cost range. With the implementation of the CFS and the EPA rule, the CEOs stated that it is unlikely that additional carbon regulation will be passed in the near future. Instead, if the United States is not on track to meet its pledge under the Paris Agreement,[21] tighter regulations on power sector emissions could be expected to come into effect by 2028.

The CEOs voiced support for keeping the five currently required scenarios. Should the Commission adopt the CEO's recommended $0 - $75/ton cost range, the low externality cost/low regulatory costs scenario (scenario C) could be discontinued as it would be identical to the low externality/no regulatory cost scenario (scenario A). However, the CEOs stated that all modeling scenarios should retain the balance of the statutorily required externalities.

The CEOs asserted that the requirement to apply the SC-GHG values prevents the Commission from allowing utility modeling to replace a carbon externality value with regulatory values, as is currently allowed and recommended by the Agencies. According to the CEOs, by mandating the use of the SC-GHG values, the legislature is requiring that climate impacts be weighed more heavily when evaluating resource options. Additionally, the CEOs stated that Minn. Stat. §216B.2422, subd.3(b) requires the Commission to use much higher CO_2 externality values than it has in the past.

The CEOs explained that allowing utilities to replace externality costs with carbon regulatory costs, once those regulatory costs are implemented, made sense when the approved externality costs were much lower than the projected regulatory cost range.[22] At that time, when the utilities would replace externality costs with carbon regulatory costs in their models, the externality costs would be reflected in the cost of the energy. However, since the externality costs became higher than the projected regulatory costs,[23] utilities were no longer fully internalizing the estimated externality costs when they replaced externality costs with regulatory costs in their models. The CEOs stated that continuing this practice will obscure future climate damages as these modeling assumptions produce situations where the estimated climate costs of certain resources drop by roughly half in 2025 instead of continuing

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21 Greenhouse gas emissions reductions of 50%-52% by 2030.

22 In 2007 the projected range of regulatory costs was $4 - $30 per ton compared to the projected range of externality costs of $0.30 - $3.10 per ton, plus inflation.

23 In 2018, the Commission decreased the projected regulatory costs to $5 - $25 per ton and increased the externality costs to $10.07 - $46.96 per ton.

to intensify. The EPA's draft social cost values, which the Commission is required to use pursuant to Minn. Stat. §216B.2422, subd.3(b), sets a mid-range carbon externality estimate of $210 per metric ton in 2025. The CEOs explained that should the Commission retain its current modeling requirements, "…it would thus be allowing utilities to imagine that payment of a mere $15 regulatory cost would be sufficient to fully internalize $210 in climate damages."[24]

The CEOs recommended that the Commission recognize the modeled regulatory costs as an internalized portion of the total externality cost. This would mean that instead of reducing the externality costs to zero when regulatory costs are applied, utilities would reduce the externality costs/ton by the size of the regulatory cost/ton, leaving the balance of the externality in place. For example, say a utility was utilizing the mid-range carbon externality estimate from the EPA's SC-GHG ($210/ton in 2025) and the mid-range regulatory cost of carbon ($15/ton) in a model. The utility would apply a $210/ton externality cost until the regulatory cost threshold year, after which, the utility would model the regulatory cost of carbon and the remaining balance of the externality cost ($210 - $15 = $195) instead of the current practice of dropping externality costs from the model entirely after the threshold year for regulatory costs.

The CEOs noted that there are no conceptual challenges created by continuing to recognize the non-internalized portion of the externality cost, citing a statement from Dr. Stephen Polasky[25] who explained that the current practice of replacing an externality value with a smaller projected regulatory cost is "inconsistent with fundamental economic principles"[26] and that "[a] regulatory cost that is only a portion of the externality cost can only partially internalize the externality cost."[27]

C. Center for Energy and the Environment

CEE stated that it is no longer necessary to include a price signal on emissions in modeling to drive emissions reductions because both the CFS and the EPA rule prescribe limits on carbon emissions. Including a regulatory cost of carbon in a capacity expansion model could create unnecessary complexity or contradictory modeling outcomes. Instead, CEE promoted

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[24] CEO initial comments, p.6

[25] The CEOs explained that Dr. Polasky, a Regents Professor and the Felser-Lampert Professor of Ecological/Environmental Economics at the University of Minnesota, has focused on environmental externalities, environmental regulation, and climate change in his research and publications; served as Senior Staff Economist for environment and resources for the President's Council of Economic Advisers (1998-1999); served on the Science Advisory Board for the EPA; coauthored the textbook *Economics and the Environment*; been author on over 250 peer-reviewed journal articles' and presented expert testimony to the Commission regarding externality values.

[26] CEO Initial Comments, Attachment: Statement of Dr. Stephen Polasky

[27] id.

alternative ways to analyze resource plans that meet the requirements of the CFS such as instituting a constraint on emissions within the capacity expansion model.

CEE recognized that Minn. Stat. §216H.06 requires the Commission to establish a likely range for the regulatory cost of carbon, and thus recommended adopting a value of $0/ton for the regulatory cost of carbon.

Although CEE does not believe a regulatory cost of carbon is necessary, they stated that such analysis may provide insight into utilities' dispatch practices. This analysis would allow regulators, utilities, and stakeholders to see how electric generation resources would be dispatched if the environmental costs of CO_2 emissions were imbedded into energy costs.

CEE continued to recommend that the Commission require utilities to apply the social cost of carbon values to electric resource plans on a post hoc basis. Such analysis does not affect resource selection within the model but provides valuable information about the environmental costs associated with different resource plan options. Should the Commission require utilities to continue including a regulatory cost of carbon in their modeling, CEE continues to recommend that the Commission no longer require modeling scenarios in which the utilities fully substitute the regulatory cost of carbon for the social cost of carbon. Having provided a similar explanation as the CEOs, CEE also recommended that Commission require utilities to account for the incremental environmental costs[28] imposed by a plan.

D. Utilities

Xcel, OTP, MP, and GRE recommended the removal of future regulatory cost of carbon values. If the Commission believes that maintaining a regulatory cost of carbon is necessary due to statutory requirements, the utilities recommended setting the regulatory cost of carbon to $0. The utilities explained that the regulatory cost of carbon has been used to predict the costs of complying with future carbon legislation. However, with the CFS and the draft EPA rule the cost of carbon legislation is no longer uncertain, thus, utilities no longer need to predict compliance costs using the regulatory cost of carbon. Additionally, MP observed that the federal government has been reducing carbon emissions using grants and tax credits instead of through carbon taxes or a cap-and-trade program. To MP, this signals that it is unlikely that carbon regulation costs will be imposed by the federal government in the future and furthers the conclusion that the continued use of the regulatory cost of carbon is not necessary.

While the utilities were united in their initial recommendation, Xcel, OTP, and GRE provided potential alternatives for the Commission to consider. For instance, Xcel was not opposed to setting a $0 per ton value for the low-end of the approved range for the predicted regulatory

[28] The incremental environmental costs would be the difference between the social cost of carbon and the regulatory cost of carbon.

cost of carbon but stated a preference for the Agencies' $30 per ton value for the upper bound. According to Xcel, maintaining the upper bound at $25/ton, or increasing it to $30/ton would maintain consistency with allowance auction clearing prices in the Western Climate Initiative (WCI). However, Xcel disagreed with the Agencies that the annual escalation factor should be set at 4%, noting that such an escalation factor exceeds industry projections and could cause resource and carbon costs to be inappropriately valued.[29] Instead, Xcel recommended that the escalation factor be set at 2%, or a value in line with a utility's assumptions around long term inflation used in its IRP. Xcel was not opposed to using 2025 as the threshold planning year for which the regulatory cost of carbon values should begin to be applied. Xcel did not provide comments regarding the proposed planning scenarios.

OTP, while favoring a regulatory cost of carbon of $0, was not opposed to the Agencies' recommendation. Additionally, OTP did not voice opposition to the use of an escalation factor of 4% as proposed by the Agencies and was not opposed the use of a 2025 application year or the proposed planning scenarios.

As an alternative to setting the regulatory cost of carbon to $0, GRE proposed using the cost of RECs for the regulatory cost of carbon. GRE explained that entities must procure RECs for each MWh of generation required to meet the CFS milestones. Therefore, the cost of complying with future carbon regulation would be the cost of purchasing the RECs required to cover any energy generated on a utility's system using non-renewable resources. GRE proposed a long-term REC value of $4/MWh to approximate the cost to forward purchase multiple years of RECs for compliance with the CFS. In lieu of providing an escalation factor for this recommendation, GRE recommended that in each annual filing in Docket No. E999/CI-07-1199, a cost estimate of a multi-year REC purchase be proposed to better approximate future marginal cost of compliance with the CFS. GRE did not provide comments on the Agencies' recommended planning scenarios.

II. Treatment of Environmental Externalities and Regulatory Costs in Modeling

Staff notes that this section will make more sense to the reader with an understanding of the terms "PVSC," or Present Value of Societal Costs, and "PVRR," or Present Value Revenue Requirement. PVSC and PVRR are terms commonly used by the Agencies, Xcel, and the CEOs to describe scenarios with or without carbon costs accounted for. They can be defined as:

- "Present value of societal cost," or PVSC, is the net present value of all of the plan's costs, including the regulatory cost of carbon and all externality costs.

[29] Xcel explained that to its knowledge, the Federal Reserve has maintained its long-term economy-wide inflation target at 2%, and the Congressional Budget Office expects that inflation rates will return to below 4% by the end of the year. Additionally, the 30-year forecast from S&P Global projects the producer price index for finished goods to be 1.58%, and both the GDP price index and the CPI to be 2.24%.

- "Present value revenue requirements," or PVRR, are all of the plans costs but does not include the regulatory cost of carbon or externality costs.

While the social cost of carbon and the regulatory cost of carbon represent different types of costs, they are both included as part of the PVSC.

A. Otter Tail Power

OTP noted that it models CO_2 regulatory costs in the same way it models environmental externalities. According to OTP, both the environmental externalities and the regulatory costs are price adders to the production costs of thermal units and market purchases based on the emission output rates and emission type costs. OTP stated:

> All else being equal, this method increases the energy dispatch cost of units that produce emissions (including market purchases) which reduces their capacity factors and incentivizes the selection of zero or low-emission resources. We note that other utilities model externalities in a slightly different fashion, and Otter Tail remains open to adopting such methods in future resource planning proceedings.[30]

B. Clean Energy Organizations

The CEOs urged the Commission to instruct utilities to model regulatory and externality costs in a way that more realistically reflects market dynamics and that clearly provides critical information about a resource scenario's costs. The CEOs explained that externality and regulatory costs have gotten lost in utility IRPs due to the fact that they are commonly undifferentiated among other modeled costs. According to the CEOs, it is not currently possible to identify the externality and regulatory costs of a utility's preferred plan, and it is not possible to analyze the reduction of regulatory and externality costs across alternatives.

Additionally, the CEOs reported that utilities each model and report on their regulatory and externality costs differently. As was noted above, OTP models both regulatory costs and environmental costs as dispatch adders whereas other utilities apply environmental costs after the capacity expansion model is run due to the fact that externality values do not impact dispatch. Regarding the variability in how environmental externality values are reported, the CEOs explained that in Xcel's prior IRP the company did not report regulatory costs as a dispatch adder as a part of the PVRR instead reported regulatory costs as a part of the Present Value Social Cost (PVSC).

For these reasons, the CEOs recommend that the Commission require utilities to:

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30 OTP initial comments, p.3

- Model future regulatory costs as dispatch adders under EnCompass because regulatory costs would actually affect dispatch (or use a comparable method under other models);
- Model externality values as post-processing add-ons under EnCompass because externality costs would not actually affect dispatch (or use a comparable method under other models);
- Identify the future regulatory costs of each scenario as part of its PVRR, because regulatory costs would be internal costs for which the utility would seek rate recovery; and
- Identify the externality costs of each scenario and present these costs separately from the PVRR.[31]

These recommendations are represented by Decision Options 9.a.-9.d.

III. Incorporation of the Carbon Free Standard

A. The Agencies

The Agencies suggested that predicting the regulatory costs associated with CFS compliance could be determined by estimating each utility's cost to meet the emissions limitations within the CFS, with the additional cost of REC purchases for any emissions in excess of the limit included in the estimate. However, the Agencies noted that the current model used in Minnesota regulatory analysis, the EnCompass model, may be limited in its ability to capture all the complexities of the CFS. This is because the CFS places limits on emissions associated with a utility's Minnesota retail sales (not total generation) and allows compliance to be achieved through the purchase and retirement of RECs. Without a dollar per ton value to input into EnCompass, it might not provide dispatch outputs that would inform compliance pathways to meet the CFS.

Given these limitations, the Agencies explored whether the recommended regulatory cost range could be modified to drive model outcomes that also meet the CFS. They issued information requests to Xcel, MP, OTP, and GRE regarding what regulatory cost of carbon was necessary for utilities to achieve compliance with the CFS within EnCompass. Additionally, the Agencies recommended that the utilities include in their reply comments the regulatory cost of carbon value consistent with their responses to the information request.

- GRE claimed to have adequate renewable generation combined with REC retirements to satisfy Minnesota's CFS requirements.
- MP stated that its 2021 IRP planning assumptions are outdated, and a detailed analysis would be required to update its IRP modeling assumptions.

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[31] The CEOs noted that since the discount rates for the GHG externality cost ranges are already built into the EPA's externality estimates and specified by the amended law, the externality costs should not be subject to any additional discounting except for during the period prior to the year the emissions occur.

- OTP stated that it expects to cover, and go beyond, its total energy delivered to Minnesota customers using a combination of renewable generation and RECs.
- Xcel stated that its IRP Alternate Plan will exceed CFS requirements.

Based on the responses received by the utilities, the Agencies concluded that the utilities' most recent IRPs, which included modeling scenarios using a range of $5 to $30 per ton of carbon dioxide, get the utilities fairly close to the decarbonization targes of the CFS. For this reason, the Agencies continued to recommend a $5 to $30 per ton range for the regulatory cost of carbon for 2023 and 2024. The Agencies stated that this range "continues to represent the agencies' best estimate for likely future system wide cost on carbon emissions for electricity generation, based on the cost of carbon credits in existing cap-and-trade systems and other markets or systems that generate a cost to emit carbon."[32]

B. Clean Energy Organizations

The CEOs stated that the Commission should not try to estimate the costs of complying with the CFS or the EPA rule in this proceeding. Unlike estimating the likely costs of a cap-and-trade system for carbon emissions in which the cost of carbon would be uniform across all utilities, the Commission cannot reasonably estimate the cost of complying with the CFS or the EPA rule because those compliance costs will vary from utility to utility and even across individual units. According to the CEOs, the lack of uniform regulatory costs makes it impossible, or at least impracticable, for the Commission to estimate the cost of compliance with either the CFS or the proposed EPA rule. Instead, the CEOs recommended that the Commission adopt an estimate of the potential additional carbon regulations that can be expected, for which the CEOs recommended a range of $0 - $75/ton, and should clarify that utilities are required to demonstrate compliance with the CFS and the EPA rule as a part of their resource plans.

The CEOs explained that utilities are already required to report their plans, activities, and progress in meeting the CFS and the renewable energy standard (RES) in their IRPs.[33] Once the EPA rule is finalized, which is currently scheduled for April 2024, the CEOs stated that utility resource plans will need to show how they will comply with the rule if adopted as proposed. The CEOs noted that such a requirement would be consistent with the forward-looking goal of section 216H.06. Therefore, the CEOs recommended that the Commission instruct utilities in their next IRPs to show how they plan to comply with both the CFS and the EPA rule. These plans must include the utility's estimated costs of achieving compliance. Without such information, the CEOs stated it would not be possible for the Commission and the public to know how the utility's plan compares to alternative compliance approaches.

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[32] Agencies initial comments, pp.5-6

[33] Laws of Minnesota 2023, chapter 7, section 11 (amending Minn. Stat. §216b.1691, subd. 3).

C. Center for Energy and the Environment

Like the CEOs, CEE recommended that the Commission not attempt to incorporate or embed the costs associated with CFS compliance within regulatory cost of carbon. As stated previously, with the introduction of the CFS, CEE does not believe that the regulatory cost of carbon continues to provide value. Rather than establishing a regulatory cost of carbon, CEE recommended that the Commission require utilities to develop and propose multiple resource plan options that meet the requirements of the CFS.

D. Utilities

Staff notes that utility comments regarding how the Commission's range of CO_2 regulatory costs should incorporate the CFS has already been captured in Party Comments Section I of this briefing paper. In summary, with the CFS and the draft EPA rule, the cost of carbon legislation is no longer uncertain, thus, utilities no longer need to predict compliance costs using the regulatory cost of carbon. For this reason, the utilities recommended the removal of the regulatory cost of carbon or setting the regulatory cost of carbon to $0. This is represented by Decision Option 2.

IV. Implementing the Federal Interagency Workgroup's Social Cost of Greenhouse Gas

A. The Agencies

The Agencies noted that the externality cost of GHGs is independent of the regulatory cost of carbon docket. Given the language of the CFS, the Agencies recommended the Commission update its order in Docket No. 14-643 to make it consistent with current statutes.

B. Clean Energy Organizations

The CEOs did not make an explicate recommendation, but stated that the legislature has, with unprecedented specificity, instructed the Commission to adopt the full range of discount rates and subsequent SC-GHG values from the IWG. They asserted that Minn. Stat. §216B.2422, subd.3(b) does not provide the Commission with the authority to replace environmental cost values with regulatory costs at a year of its choosing.

C. Center for Energy and the Environment

CEE recommended that the Commission require utilities to apply the SG-GHG values at the central estimate, or 2% discount rate, rather than the full range. CEE stated that it is not necessary to require utilities to apply a range of values for the environmental externality costs of CO_2. Because externality values are applied to a modeling outcome by multiplying the estimated externality cost value by the total projected tons of CO_2 emissions, including a higher or lower overall estimated environmental externality cost would produce a higher or lower overall estimated externality proportionate to the difference in the estimated externality value.

CEE stated that directionally and comparatively, applying different values would have no effect.

CEE noted that the IWG's work is ongoing, and updated SC-GHG estimates are forthcoming. CEE recommended that the Commission request comments in this docket or in Docket No. 14-643 to consider a process to review and adopt future IWG SC-GHG estimates.

D. Utilities

Xcel recognized that the Commission is required to evaluate the SC-GHG values but recommended that these values be used in a sensitivity analysis. Additionally, the Company recommended that that the SC-GHG values be considered as an externality in resource planning.

Xcel reported that there are questions regarding the technical shortcomings of the draft values from "parties with extensive knowledge in SC-GHG modeling and calculations including the Electric Power Research Institute (EPRI).[34] Moreover, Xcel noted that the EPA's values "do not conform to the recommendations of the National Academies of Science."[35]

Additionally, Xcel noted that it is unknown if final values will ever be published, and if they are, how the final values may differ from the EPA's draft values with improved methodologies. Xcel also noted that the EPA did not use their draft SC-GHG values in their most recently-published draft power sector GHG standards, and instead utilized the interim IWG values.

OTP stated that utilities are required to use the EPA's social cost values in conjunction with other external factors when evaluating resource options. OTP stated that it anticipates the Commission's Order would replace the current social cost of carbon values with the EPA's values, but otherwise not change how these values are applied as a part of resource planning.

V. Incorporation of the EPA's CO_2 Regulation under Sections 111(b) and (d)

Under Section 111(b) of the Clean Air Act (CAA), EPA sets New Source Performance Standards (NSPS) for GHG emissions from new, modified, and reconstructed fossil fuel-fired power plants.

Under Section 111(d) of the CAA, EPA requires states to submit plans to establish "standards of

[34] EPRI stated: "After thoroughly reviewing EPA's draft new methodology, we find that the methodology and estimates are not yet scientifically reliable and robust for policy use. The methodology contains multiple significant technical issues and does not satisfy the NASEM recommendations. This should be addressed before the estimates are deployed to inform policy, for this rule and otherwise." – EPRI Public Comments on U.S. EPA Proposed Oil and Gas Methane Rule and Draft New SC-GHG Estimation Methodology (Docket ID No. EPA-HQ-OAR-2021-3017), at p.2, https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2361

[35] Xcel, July 14, 2023, comments, p. 9.

performance" for certain air pollutant emissions from existing facilities. State plans must generally establish standards that are at least as stringent as EPA's emission guidelines.

On May 11, 2023, EPA proposed CAA emission limits and guidelines for CO_2 from new gas-fired combustion turbines, existing coal, oil, and gas-fired steam generating units, and certain existing gas-fired combustion turbines.

EPA has proposed two main rules:

- One sets NSPS for new fossil fuel-fired stationary combustion turbine power plants (primarily natural gas-fired units) and fossil-fuel fired steam generating units that undertake a major modification (primarily coal-fired units).

- The second sets guidelines for GHG emissions from existing fossil fuel-fired steam generating power plants and the largest, most frequently operated existing stationary combustion turbines, and it solicited comment on approaches for setting guidelines for GHG emissions for the remainder of the combustion turbine category.

The Commission's March 29, 2023, *Second Notice of Extended and Supplemental Comment Period* asked parties how, or if, the Commission should incorporate potential regulatory costs resulting from any forthcoming EPA regulations of CO_2.

A. The Agencies

The Agencies recommended that the Commission continue to monitor the development of the EPA's GHG Power Plant Rule to determine which fossil-fuel units in Minnesota will be covered by the final rule, what emission limits will apply to each unit, and the compliance timelines and pathways that will be available in the final rule for each unit.

The Agencies noted that because the proposed rule is still open for comment, and is subject to significant public interest, it is difficult to determine the full impact of the EPA's proposed GHG Power Plant Rule on fossil fuel power plants in Minnesota. To understand the rule's impact, the Agencies stated that they, and the utilities, will need:

> …significantly more clarity regarding which fossil-fuel plants in Minnesota will be covered by the rule, the compliance timelines for each type of covered unit, the emission limits applicable to each type of covered unit at the different phases of the rule, the available compliance pathways for each covered unit, and the timeline for development of state plans to establish enforceable requirements on covered units.[36]

Because the EPA's proposed GHG Power Plant Rule has different timelines than the CFS and operates on a unit-by-unit basis, the Agencies stated that it is conceivable that the EPA's rule

[36] Agencies initial comments, p.8

could create additional compliance costs, beyond the costs for meeting CFS requirements. The EPA's rule may create a unit-specific regulatory cost applied in resource planning that would increase the complexity of modeling.

B. Clean Energy Organizations

Staff notes that the CEO's opinion on the EPA rule is identical to their option on the CFS. The CEOs stated the Commission need not try to estimate the costs of complying with the EPA rule in this proceeding. Instead, the CEOs recommended the Commission require utilities to show how they plan to comply with the CFS and the EPA rule in their next IRPs. These plans must include the utility's estimated costs of achieving compliance.

C. Center for Energy and the Environment

Similar to the comments made by the CEOs, CEE recommended that, once the proposed EPA standards are finalized, the Commission require utilities to provide a description on how they plan to comply with the EPA's new carbon pollution standards for each applicable plant they own and operate, and how the EPA standards affect compliance with the CFS.

D. Utilities

Xcel acknowledged the affect the proposed EPA rule would have on future resource plans. However, the Company noted that the emissions limits and retrofit requirements included in the final rule would be more appropriately modeled as constraints or direct equipment investment costs instead of proxied via future regulatory carbon costs. Additionally, Xcel highlighted that the rule is currently in a draft form, and it may be premature to consider the full cost impacts.

GRE stated that the costs associated with the final version of the EPA rule will be reflected in the capacity expansion modeling work as all other emissions standards are under the CAA. GRE did not recommend that any additional costs be considered by the Commission and applied to emissions in this case.

OTP is evaluating the proposed EPA GHG Power Plant Rule and how they may affect resource planning. The Company stated that it intends to file preliminary comments on the proposed rule in August 2023, however, at this time OTP believes it is too early in the rulemaking process to assess the regulatory costs of the proposed rule.

REPLY COMMENTS

I. Clean Energy Organizations

The CEO disagree with the Agencies' recommendation to retain environmental externalities in a single modeling scenario and continued to recommend that the balance of externalities be retained in utilities' modeling scenarios.

The CEOs explained that the Agencies' acknowledged that retaining environmental impact of emissions for all years may benefit the Commission's decision making. Having already discussed why retaining the environmental costs for all scenarios is required on legal and economic grounds, the CEOs used part of their reply comments to build off of the Agencies' comments and discuss why maintaining environmental costs is warranted on the grounds of providing useful information.

As explained by several participants, externality values are typically modeled as a post-processing add-on that does not influence which resources the model selects and how those resources are dispatched. Additionally, the costs associated with environmental externalities does not deprive utilities or the Commission of useful information about rate impacts. The direct cost of a resource mix to rate payers is presented in the PVRR. Retaining the balance of the externalities will appear solely in the PVSC. The CEOs stated that externality values tell the Commission, the utilities, and the public how much damage the emissions from a particular resource mix are projected to do to society and the environment via climate change.

The CEOs also responded to Xcel's comments disputing the EPA's draft estimates of the social cost of carbon. Despite Xcel's questioning of the EPA's values, the CEOs explained that the legislature not only accepted the EPA's draft estimates of the social cost of carbon, but they adopted them into law. The CEOs recommended that the Commission not evade the statutory requirement to use the EPA's values by limiting their application to a single sensitivity analysis.

Finally, the CEOs reaffirmed their recommendation for the Commission to adopt a $0-$75/ton regulatory cost of carbon range beginning in 2028, noting that all parties except for the Agencies indicated that there is no need for the Agencies' proposed $5-$30/ton range as an estimate of the costs of complying with the CFS. The CEOs agreed that utilities will need to incorporate utility-specific changes to demonstrate compliance with the CFS and the proposed EPA rule.

The CEOs stated that not making any estimate for future regulatory costs would sidestep section 216H.06, which requires the Commission to estimate the likely rage of costs of future CO_2 regulation on electricity generation. Additionally, the CEOs asserted that setting the regulatory cost to $0/ton would not constitute compliance, noting that there is no reasonable basis for the Commission to find that there is zero risk of additional regulatory costs facing utilities beyond the CFS and the EPA proposed rule.

The CEOs explained that Section 216H.06 requires the Commission to anticipate future laws, to make sure long-term plans reflect the regulatory risk inherent in their carbon emissions as the world struggles to address the climate crisis. The CEOs stated that their proposed $0 - $75/ton regulatory cost range beginning in 2028 is reasonable. The IMF found that the upper cost value of $75/ton was needed in high income nations to reduce emissions in line with keeping warming below the less-ambitious Paris Agreement limit of 2^{o}C. This value reflects the possibility that in response to rising temperatures, the U.S. will take additional regulatory steps to stay within the warming limits while the lower $0 value reflects the possibility that utilities will not face additional carbon limits, which could happen if utility decarbonization is driven at a sufficiently fast pace by technological and economic advances and by subsidies rather than by carbon limits.

II. Xcel Energy

In its reply comments, Xcel continued to support setting the regulatory cost of carbon at $0/ton, noting that recent state and federal policies will require Minnesota utilities to "internalize" these costs and so a regulatory cost of carbon may no longer be needed. Xcel noted that this recommendation is in line with climate science, citing analysis by Rhodium Group which showed that current or proposed climate policies, including the Inflation Reduction Act (IRA), put meeting U.S. emission reduction targets under the Paris Agreement within reach.[37]

However, Xcel recognized that statute may require the Commission to set a non-zero upper bound, and thus would not be opposed to a $0/ton lower bound and the Agencies' recommended $30/ton upper bound. Xcel warned against adopting the CEO's recommended regulatory cost upper bound of $75/ton, stating that such a recommendation is "highly speculative" and that implementing a higher regulatory cost of carbon than has been used in the past would drive significant increases in system costs and risk sacrificing affordability.

Xcel continued to support the adoption of the IWG's draft cost of greenhouse gas emissions via an additional sensitivity, and the use of PVSC to summarize CO_2 externality costs. Regarding the CEO's recommendation that the Commission recognize the modeled regulatory costs as an internalized portion of the total externality cost, Xcel stated the following:

> The social cost of carbon is appropriate to consider as an externality cost that is calculated after resource selection and dispatch simulation in our modeling. The CFS references consideration of the federal social cost of carbon estimates but does not direct utilities to fully internalize and pass these costs on to customers. In other words, the regulatory cost of carbon does not, and should not, equal the social cost of carbon if the cost to comply with regulations is lower.[38]

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[37] "The full suite of current policies on the books as of June 2023 drives US emissions to 32-51% below 2005 levels in 2035. Along the way, the US will achieve a 29-42% reduction in GHGs in 2030—a meaningful departure from previous years 'expectations for the US emissions trajectory but not enough for the US to meet its pledge under the Paris Agreement to reduce emissions by 50-52% below 2005 levels by 2030. The difference between our estimate's low and high ends is primarily driven by faster economic growth, cheaper fossil fuels, and more expensive clean energy technologies." – Rhodium Group, *Taking Stock 2023 US Emissions Projections after the Inflation Reduction Act*, July 20, 2023, p.4, https://rhg.com/wp-content/uploads/2023/07/Taking-Stock-2023_Rhodium-Group.pdf

[38] Xcel reply comment, p.5

III. Minnesota Power

MP continued to recommend the regulatory cost of carbon be set at $0/ton as utilities must already plan for carbon-free systems in Minnesota. However, MP clarified that like Xcel and OTP, they would not object to a lower bound of $0/ton and an upper bound of $30/ton for CO_2 planning purposes. MP stated that the escalation factor should be in line with utility's assumptions around long-term inflation used in its IRP. MP is not opposed to either a threshold planning year of 2025 or 2028 but noted that with a $0/ton regulatory cost of carbon the threshold planning year should be 2023. The company does not object to continuing to use the current planning scenarios.

MP's next IRP will cover planning years 2025-2040. MP explained that this IRP will set forth a plan to comply with applicable state and federal laws, including the CFS. MP agreed with OTP that future regulatory cost of carbon estimates should be used for informational purposes only, as many of the future planning decisions will be driven by CFS compliance. MP also agreed with Xcel that the SC-GHG values should be treated as an externality within a scenario or as a sensitivity if it is not included in the scenarios.

STAFF ANALYSIS

As previously stated, the Commission has several decisions to make when establishing a regulatory cost range for 2023, including:

- Setting the regulatory cost range and escalation factor;
- Establishing the effective date for the regulatory cost of carbon;
- Setting modeling scenarios;
- If, or how, the CFS and the EPA's draft rule should be considered with regard to the regulatory cost of carbon and related modeling scenarios;
- How to respond to Minn. Stat. § 216B.2422, subd. 3 to require the Commission to "provisionally adopt and apply" a version of the federal social cost of carbon; and
- Whether or not to apply the established regulatory costs to both 2023 and 2024.

I. Regulatory Range and Escalation Factor

A. Cost Range

Based on the recommendations made by parties, the Commission has four values to choose from – two at the low end and two at the high end – that would establish a regulatory cost range. The Agencies recommend $5-$30/short ton, while the CEOs propose the broadest range, $0-75/short ton. It would appear that the Commission can therefore choose between:

- $0 or $5 at the low end, and
- $30 or $75 at the high end.

Regarding to two ends of the range, at the low end, Staff believes $5/ton is well-supported by the record, and while parties make valid points for $0, Staff supports a non-zero number as an appropriate reflection of the financial risk associated with carbon-emitting generation. While it is true that utilities continue to decarbonize, moving toward a carbon-free system arguably does not remove the risk of additional costs from future CO_2 regulation, and future carbon regulation may add additional costs for utilities despite being carbon-free in the context of the CFS. If, for instance, a federal carbon tax or regional cap-and-trade system is put in place, Minnesota utilities may still be subject to additional costs associated with their carbon emissions even if the utility is in compliance with the CFS.

Having said that, there is not robust analysis on this record stating why $5/ton is likely, outside of the Agencies' argument that "there is still not sufficient objective basis for significantly changing the current cost range." Oher than OTP, all other parties stated a preference for a $0 low end. Still, $5/ton is, in Staff's view, the best non-zero low end that was proposed.

As a point of clarification, Staff supports utilities continuing to model a $0 carbon cost scenario as they presently do; the distinction is that Staff does not believe $0 belongs in the regulatory cost range. To explain, some utilities file resource plans in jurisdictions where externalities are prohibited by that jurisdiction, and those utilities model no-carbon costs scenarios. Other utilities choose to model a no-externalities case because there is currently no federal tax in place. In Staff's view, there is no reason to prohibit utilities from continuing to model these runs, as they provide consistency across jurisdictions and informational value about carbon pricing. The point is that since utilities will continue to model $0 as part of a full suite of cost scenarios, there is no need for the Commission to take the added step of incorporating $0 into the CO_2 regulatory cost range.

As for the high end, the Commission's options, based on party recommendations, are either $30/ton or $75/ton. The majority of parties supported $30/ton, whereas the CEOs were the only party to support $75/ton. Staff has no position on the high end but notes that the differences between the recommendations rest on whether it is more reasonable to take a market-oriented approach, factoring in allowance prices in existing carbon markets, or whether utilities should plan for more ambitious, aggressive decarbonization efforts such as meeting the commitments made under the Paris Agreement.

B. Escalation Factor

From Staff's perspective, it is unclear what exactly the escalation factor is attempting to capture, and therefore Staff takes no position on the Agencies' proposed 4% escalator versus Xcel's 2% escalator. There also does not appear to be any calculation on the impact of 4% versus 2% over a long-term time horizon that may inform how the values will be used over an asset's economic life. For instance, if a model run extends to 2050, it is unclear why an escalator should extend to 2050 to begin with, given the underlying rationale to track allowance markets.

The Agencies' report acknowledged that "the Commission has not specified an escalation factor for these costs in its past orders and utilities have been using different values in their planning process," which only adds to the need for additional clarification on the basis for, and financial impact of, an escalator. For example, if market clearing allowance prices in WCI and RGGI have had an upward trend, the justification for assuming prices should continue at 4% over an entire planning period or asset life is not well-supported. Moreover, the Agencies seem to simultaneously argue that increasing the upper bound from $25 to $30 capture the recent uptick in allowance prices, yet an escalation factor is needed for this same reason. In other words, it is unclear why an escalation factor is needed on top of increasing the upper bound. Finally, Xcel differs from the Agencies on this issue even though the Agencies cited Xcel's comments when originally making this recommendation (thus making it unclear why the two parties are now opposed to one another).[39] Ultimately, the Commission may need additional clarification regarding the relationship between the increase to the upper bound and the escalation factor before making a decision.

II. Threshold Planning Year

The proposed threshold years are:

- 2025 (Agencies), OR
- 2028 (CEOs), OR
- 2023 (MP).

Staff interprets the rationale for these three options as follows:

1. The Commission may select 2025 if it finds there is no reason to change the decision from the September 2020 order.

2. The Commission may select 2028 if it agrees with the CEOs that the federal government's utilization of incentives to drive decarbonization, and Minnesota's enactment of the CFS, reduces the likelihood of additional carbon-related regulatory costs in the short-run.

3. The Commission may select 2023 if it finds that the enactment of the CFS will result in little to no risk of additional future climate legislation, and a flat $0/ton value is the best approximation for the regulatory cost of carbon.

Two things to consider about the threshold year are that (1) it has been approximately three years since the Commission's last order in this proceeding, and (2) if the range attempts to reflect *additional* climate policies (and not the CFS or EPA rule), then there should be a realistic assumption for an implementation period. Xcel noted that "[n]o federal legislative framework regulating carbon emissions from the electric sector has passed, or even gained significant

[39] See Agencies report, p. 5.

traction, since the Commission's last update."[40] Without any imminent, additional carbon legislation, assuming the same threshold year as an order from three years ago may seem unrealistic.

III. CFS and the EPA's draft rule

Before addressing this issue, Staff notes that IRPs must comply with all statutes and regulations affecting utility operations. Therefore, regardless of the Commission's decision in this case, utilities must demonstrate how a proposed IRP will comply with the CFS and EPA GHG Power Plant Rule (in addition to the Renewable Energy Standard, Greenhouse Gas Reduction Goal, and so on). If an IRP fails to incorporate this analysis, it would be deemed incomplete, and the utility would be required to supplement its IRP. What this means in the context of this proceeding is that the Commission does not need to take any action with respect to requiring compliance with the CFS or EPA GHG Power Plant Rule, although the Commission can certainly reinforce this requirement in its order.

The Commission's options regarding how to incorporate the CFS into this proceeding can be summarized by three distinct party positions:

- The Agencies' proposed range of $5-$30, which is similar to the current range, gets utilities fairly close to the CFS targets. Put another way, the values should incorporate the CFS, but since the CFS functions essentially as a cap-and-trade regime without tradeable permits, a proxy cost is instructive to ensure utilities remain on a path of compliance; the Agencies believe its range is a reasonable proxy cost.

- The Commission should not incorporate the CFS for the purposes of establishing an estimate of likely costs to comply with future CO_2 regulation. Instead, the CFS should be examined on a utility-specific basis in their respective IRPs, and the regulatory costs should be based on additional future climate policy.

- Given the CFS and the legislature's requirement that the Commission adopt the FSCC, CO_2 regulatory costs are no longer needed and should be set to $0.

Staff's conclusion is that the regulatory costs of carbon used up to this point adequately prepared our utilities for the future CO_2 regulation that was the CFS, resulting in many utility plans getting "fairly close" to the decarbonization targets of the CFS as stated by the Agencies in their comments. The Commission should strive to continue to use the regulatory cost of carbon to predict additional future CO_2 regulation in addition to the CFS.

To be clear, Staff does not believe the Agencies' recommended $5-$30/ton regulatory cost

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[40] Xcel July 14, 2023, reply comments, p. 6.

range is unreasonable, but instead suggests that the Commission should select a regulatory cost range based on the predicted costs of future carbon regulation and not the costs of complying with the CFS. If the Commission were to adopt the Agencies' recommended $5-$30/ton regulatory cost range, it should be based on the analysis provided in their report, which stated that the $5-$30/ton regulatory cost range was warranted due to the combination of future regulatory uncertainty and rising allowance prices in U.S. carbon markets.

Minn. Stat. § 216H.06 requires the Commission to estimate likely costs of future CO_2 regulation. Staff recommends that the Commission base its decision on the likelihood, and predicted cost, of future CO_2 regulation and not the cost of complying with the CFS. It is staff's understanding that the costs of complying with the CFS are no longer encompassed under "likely costs of future CO_2 regulation" because the CFS is no longer an unknown future CO_2 regulation.

IV. Social Cost of Greenhouse Gases

The legislature's revisions to Minn. Stat. § 216B.2422, subd. 3 clearly require the Commission to adopt the SC-GHG values, but it is less clear when, in what docket, or what the relationship should be to the Commission's current externality and regulatory costs. Since the revisions were made to the resource planning statute, and the Commission most recently adopted a version of the FSCC in the environmental externalities docket (Docket No. 14-643), the natural fit would be to update the Commission's decision in that proceeding. However, Staff sought comment on this issue in the Commission's March 29, 2023, *Second Notice of Extended and Supplemental Comment Period* to help the Commission answer these questions.

The argument for adopting the SC-GHG values in this docket would be that modeling the two types of CO_2 costs are addressed simultaneously and regularly. However, as noted, the argument for addressing issues related to the SC-GHG values to Docket No. 14-643 would be that that is the more relevant docket, and providing notice to the parties in that docket would be appropriate.

Alternatively, the Commission may decide that it does not need any further comment because the statute is clear that the SC-GHG values must be used in all resource planning and acquisition proceedings. If the Commission adopts this view, it could still be useful if the Commission defines how the modeling scenarios should consider the relationship between social costs and regulatory costs.

Should the Commission choose to handle the SC-GHGs as a part of this proceeding instead of in Docket No. 14-643, parties recommended the following three options for handling the legislature's revisions:

1. Adopt the full range of the SC-GHG values (as recommended by the Agencies and CEOs);
2. Adopt a central, or two percent estimate, in place of CO_2 regulatory costs (as CEE recommends); or
3. Adopt the SC-GHG values as a sensitivity (as Xcel recommends).

Staff interprets the Agencies' and CEE's position to be to replace the Commission's current externality values with some, or all, of the SC-GHG values, while Xcel recommends using the SC-GHG's CO_2 values in addition to the Commission's January 2018 externalities order values as an additional sensitivity.

Decision Options 11 through 14 outline the recommendations made by parties regarding how the Commission should handle the adoption and application of the draft SC-GHG valuations presented in the United States Environmental Protection Agency's EPA External Review Draft of *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances.* Decision Option 11, as recommended by the Agencies, would have the Commission update its most recent GHG externality Order Docket No. 14-643 to provisionally adopt and apply the EPA's SC-GHG values.

Staff notes that in Docket 14-643, the Commission also set values for the environmental cost of $PM_{2.5}$, NO_X, and SO_2 (collectively, the "criteria pollutants").[41] These costs vary based on the region of Minnesota in which they were emitted. The SC-GHGs do not include values for the Commission's criteria pollutants, and recommendations to replace the Commission's externality values with the SC-GHG values, including the Agencies' recommendation, did not discuss how, or if, any consideration was given to the criteria pollutants before the party arrived at their recommendation.

The recommendations from both CEE and Xcel (Decision Options 12 and 13, respectively) are exclusive to the externality values for CO_2. Should the Commission adopt either recommendation, the Commission will likely need to make decisions on how to adopt the remaining SC-GHG values (Methane (CH_4), and Nitrous Oxide (N_20)) and how to handle the currently utilized values for criteria pollutants at a later date. This is due to the Commission being required by Minnesota Session Laws 2023, Chapter 7, section 18 to provisionally adopt and apply the draft cost of greenhouse gas emissions valuations presented in the EPA's External Review Draft of *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, which includes values for CO_2, CH_4, and N_2O. Should the Commission adopt either Decision Option 12 or 13, it may also wish to adopt Decision Option 14 and open a Comment Period in Docket No. 14-643 to discuss the remaining SC-GHG values and the Commission's criteria pollutants.

However, Staff notes that CEE's recommendation raises additional questions for the Commission, as they recommended only adopting the draft report's central discount rate of 2% while Minnesota Session Laws 2023, Chapter 7, section 18 requires the Commission to adopt "the full range of discount rates from 2.5 to 1.5 percent, with two percent as the central estimate."

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[41] See January 3, 2018 Order in Docket No. E-999/CI-14-643, https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={5066BD60-0000-C71B-9B5B-305CF65BCAE1}&documentTitle=20181-138585-01

Due to the questions that remain regarding the adoption of the EPA's SC-GHGs, Staff would recommend that decisions to replace the Commission's current externality values with the SC-GHG values be made in Docket No. 14-643. Therefore, the most appropriate path forward would be to adopt Decision Option 14 and resume this discussion in the Commission's externality values docket.

V. Setting modeling scenarios

The table below shows the Commission's five modeling scenarios required as part of its September 30, 2020, regulatory costs order. The scenarios are labeled A-E to indicate Order Points 2.A. through 2.E.

Note that environmental externalities are required in all five scenarios. Environmental externalities are replaced by regulatory costs only in the Reference Case and in the regulatory cost scenarios (when regulatory costs and environmental costs appear in the same model run).

Table 7: Current Modeling Scenarios

	Scenarios	Before 2025		2025 and Thereafter	
		Environmental Cost	Regulatory Cost	Environmental Cost	Regulatory Cost
A	Low Environmental Cost	Low End Environmental Costs for all Planning Years			
B	High Environmental Cost	High End Environmental Costs for all Planning Years			
C	Low Environmental/Regulatory Costs	Low End	-		$5/Ton
D	High Environmental/Regulatory Costs	High End	-		$25/Ton
E	Reference Case Scenario	Middle to High End	-	Middle to High End	Middle to High End

Table 8 below has been provided by Staff to aid Commissioners in visualizing the decisions before them in this proceeding. It is based on the table used to visualize the Commission's adopted planning scenarios in the September 30, 2020 Order, but has been adapted to highlight the various recommendations made by parties. Parties' recommendations are shown in red as edits to the September 30, 2020, Commission scenarios. These edits include:

- 2023 and 2028 threshold years first proposed by MP and the CEOs, respectively.
- the environmental cost scenarios include options to either replace the Commission's current values with the SC-GHG values or model them as a sensitivity to the current

externality values. (The full range of the SC-GHG values means the 1.5% (high) to 2.5% (low) discount rates.)

- the proposed alternative cost ranges, including escalation factors (which have not been part of past orders); and
- the CEOs' recommendation to retain the non-internalized portion of the externalities in the regulatory cost scenarios instead of having these costs drop off after the threshold planning year.

As with the table above, scenarios are labeled A-E to indicate Order Points 2.A. through 2.E.

Table 8: Parties' Recommended Scenarios (edits to September 30, 2020 Order in Red)

	Scenarios	Before 2025 OR 2023 OR 2028		2025 OR 2023 OR 2028 and Thereafter	
		Environmental Cost	Regulatory Cost	Environmental Cost	Regulatory Cost
A	Low Environmental Cost	Low End PUC OR FSCC Environmental Costs for all Planning Years			
B	High Environmental Cost	High End PUC OR FSCC Environmental Costs for all Planning Years			
C	Low Environmental/Regulatory Costs OR Remove Scenario If Low End Regulatory Costs Equal $0/Ton	PUC Low End OR FSCC	-	Non-Internalized Portion of the Externality Costs	$0/Ton OR $5/Ton
D	High Environmental/Regulatory Costs	PUC High End OR FSCC	-	Non-Internalized Portion of the Externality Costs	~~$25/Ton~~ $30/Ton OR $75/Ton
E	Reference Case Scenario	PUC Middle to High End OR FSCC	-	Middle to High End OR Non-Internalized Portion of the Externality Costs	Middle to High End

These scenarios do not include escalation factors. However, staff notes that the Commission may choose between a 4% escalation factor as recommended by the Agencies, or a 2% escalation factor as recommended by Xcel and MP.

While such information has to some extent been covered already, Staff provides the following notes to assist the Commission's understanding of Table 8 above:

- ***Scenarios A through E*** all include the Commission's externalities established in its January 2018 in Docket No. 14-643. ***Scenarios A and B*** are externalities-only scenarios. If the Commission <u>replaced</u> the Commission's externalities with the FSCC, the low end would increase from roughly $14.8 to $140 in 2030. Since externalities are costs to society, they would not be reflected in rate impact calculations.

- ***Scenarios C and D*** are regulatory cost scenarios, although they currently apply externalities only until regulatory costs kick in. Both externalities and regulatory costs are part of the PVSC calculation,[42] although it could be argued that since regulatory costs are likely ratepayer impacts, they should be considered in the PVRR.

- ***Scenario E*** is the Reference Case, which gives utilities an option to include a midpoint. Not all utilities run this scenario; Xcel, for example, used Scenario D as its Reference Case. Staff is generally unconcerned about which scenario is selected as the utilities' Reference Case. While the CEOs argued that the base case is subject to the most rigor and "typically the focus and an IRP and the Commission's consideration," Staff believes this is an unsupported, speculative statement about past and future IRP outcomes. In resource planning, utilities, the Department, and intervening parties conduct extensive scenario and sensitivity analyses such that the Commission is presented with a thorough record on which to make informed decisions over a range of outcomes.

Finally, the Agencies suggested that the Commission should consider including a modeling scenario that would recognize the human and environmental impacts of emissions that occur in all years, including those where the regulatory cost of carbon is applied. Staff's understanding of this suggestion is that the Commission could require utilities to retain the non-internalized portion of the externality costs (I.e., the externality cost minus the regulatory cost) as an additional modeling scenario instead of for all scenarios as recommended by the CEOs and CEE. However, additional information is needed for this recommendation, such as whether to use high, low, or middle regulatory and externality costs. Such information could be provided at the agenda meeting should the Commission wish to follow up on this recommendation.

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[42] Xcel stated on page 4 of their July 14, 2023, comments: "[T]he Company used all five scenarios in our recently filed 2020-2034 Upper Midwest Integrated Resource Plan. Option D – <u>high CO_2 environmental costs through 2024, high CO2 regulatory costs thereafter – was selected as the basis of our primary PVSC scenarios</u> and we conducted analysis on the remaining options as sensitivities. The Company also provides sensitivities that examine future scenarios with no CO2 costs incorporated – or our PVRR cases – as a comparison point…"

DECISION OPTIONS

Decision options 1-4. Are mutually exclusive

Range of Regulatory Costs

1. Establish the range of regulatory costs of carbon dioxide emissions as $5 to $30 per short ton effective 2025 and thereafter with an annual escalation factor of 4%. (Agencies, OTP not opposed)

OR

2. Establish the range of regulatory costs of carbon dioxide emissions as $0 per short ton effective 2023 and thereafter. (CEE, GRE, MP, Xcel)

OR

3. Establish the range of regulatory costs of carbon dioxide emissions as $0 to $30 per short ton effective 2025 and thereafter. (Xcel, MP)
    a. With an annual escalation factor of 2%
    b. With an annual escalation factor equal to utilities inflation assumptions.

OR

4. Establish the range of regulatory costs of carbon dioxide emissions as $0 to $75 per short ton effective 2028 and thereafter with an annual escalation factor of 4%. (CEO)

Modeling Scenarios

5. Continue using the five modeling scenarios outlined in order point 2 of the Commission's September 30, 2020 Order in Docket No. E999/CI-07-1199. (Agencies, MP and OTP not opposed)

Decision Option 6 is available should the Commission select Decision Option 2, 3, or 4 (a regulatory value of $0 or a lower bound of $0).

6. Continue using scenarios A, B, D, and E as described by order point 2 of the Commission's September 30, 2020 Order in Docket No. E999/CI-07-2299. (CEO)

7. Require utilities to retain the non-internalized portion of the externality costs (I.e., the externality cost minus the regulatory cost) in their modeling scenarios. (CEE, CEO)

8. Require utilities to retain the non-internalized portion of the externality costs (I.e., the externality cost minus the regulatory cost) as a new modeling scenario. (Agencies)

9. Require utilities to: (CEO)
    a. Model future regulatory costs as dispatch adders under Encompass (or a comparable method using other models)
    b. Model externality values as post-processing add-ons under encompass (or a comparable method using other models)
    c. Identify the future regulatory costs of each scenario as part of its PVRR; and
    d. Identify the externality costs of each scenario separately from PVRR.

<u>Carbon Free Standard and EPA Rule</u>

10. Require utilities to demonstrate in their IRPs how they plan to comply with the Carbon-Free Standard, and (once finalized) the EPA's CO_2 regulation under the Section 111(b) and (d) rules. (CEO, CEE)

<u>Social Cost of Greenhouse Gases</u>

Decision Options 11 through 13 are mutually exclusive.

11. Update the Commission's January 3, 2018 Order in Docket E-999/CI-14-643 to provisionally adopt and apply the draft cost of greenhouse gas emissions valuations presented in the United States Environmental Protection Agency's EPA External Review Draft of Report on the Social Cost of Greenhouse Gases released in September 2022, and its successors. (Agencies)

12. Require utilities to apply the environmental externality cost of CO_2 using the draft cost of greenhouse gas emissions valuations presented in the *United States Environmental Protection Agency's EPA External Review Draft of Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*, released in September 2022, with a 2% discount rate in all resource acquisition scenarios. (CEE)

13. Require utilities to utilize the draft federal social cost of carbon (FSCC) in a sensitivity analysis. These costs shall be considered an externality. (Xcel)

14. Direct Staff to open a Comment Period in Docket No. E999/CI-14-643 to consider a process for the review and adoption of future federal interagency workgroup (IWG) estimates of the social cost of CO_2 after the IWG releases updated values for the social cost of CO_2. (CEE)

<u>Application of Chosen Regulatory Costs to Filings Across Multiple Years</u>

15. Apply all regulatory cost assumptions and modeling scenarios ordered in this proceeding to all electricity generation resource acquisition proceedings during 2023 and 2024. (Agencies)

APPENDIX 1

Estimates of the Social Cost of Greenhouse Gases (SC-GHG), 2020-2080 (2020 dollars)[43]

SC-GHG and Near-term Ramsey Discount Rate									
	$SC\text{-}CO_2$ (*2020 dollars per metric ton of CO_2*)			$SC\text{-}CH_4$ (*2020 dollars per metric ton of CH_4*)			$SC\text{-}N_2O$ (*2020 dollars per metric ton of N_2O*)		
Emission Year	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%	2.5%	2.0%	1.5%
2020	120	190	340	1,300	1,600	2,300	35,000	54,000	87,000
2030	140	230	380	1,900	2,400	3,200	45,000	66,000	100,000
2040	170	270	430	2,700	3,300	4,200	55,000	79,000	120,000
2050	200	310	480	3,500	4,200	5,300	66,000	93,000	140,000
2060	230	350	530	4,300	5,100	6,300	76,000	110,000	150,000
2070	260	380	570	5,000	5,900	7,200	85,000	120,000	170,000
2080	280	410	600	5,800	6,800	8,200	95,000	130,000	180,000

Values of SC-CO2, SC-CH4, and SC-N2O are rounded to two significant figures. The annual unrounded estimates are available in Appendix A.4 and at: www.epa.gov/environmental-economics/scghg.

[43] See Table ES.1 of the EPA's External Review Draft of *Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*.