MINNESOTA
PUBLIC UTILITIES COMMISSION

Staff Briefing Papers

Meeting Date	**July 17, 2025**	**Agenda Item 1****
Company	All Electric Utilities	
Docket No.	E-999/CI-23-151	
	In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. §216B.1691.	
Issues	1. When and how should utilities report preparedness for meeting upcoming CFS requirements? 2. By which criteria and standards should the Commission measure an electric utility's compliance with the CFS? 1. What considerations should the Commission take into account regarding the double counting of Renewable Energy Credits (RECs) to meet multiple requirements? 3. How should net market purchases be counted towards CFS compliance? 5. Are there other issues or concerns related to this matter?	

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✓ **Relevant Documents**	**Date**
Initial Comments, Minnesota Center for Environmental Advocacy, Sierra Club, and Fresh Energy (collectively, "Clean Energy Organizations" or CEOs)	January 29, 2025
Initial Comments, Central Municipal Power Agency/Services (CMPAS)	January 29, 2025
Initial Comments, Connexus Energy (Connexus)	January 29, 2025
Initial Comments, Center for Resource Solutions (CRS)	January 29, 2025
Initial Comments, Carbon Solutions Group (CSG)	January 29, 2025
Initial Comments, Department of Commerce, Division of Energy Resources (DOC DER or Department)	January 29, 2025
Initial Comments, Great River Energy	January 29, 2025
Initial Comments, Health Professionals for a Healthy Climate, Climate Generation, CURE, Minnesota Environmental Justice Table, Minnesota Interfaith and Light, MN350, and Sierra Club North Star Chapter (HPHC et. al.)	January 29, 2025
Initial Comments, Minnkota Power Cooperative (Minnkota)	January 29, 2025
Initial Comments, Minnesota Large Industrial Group (MLIG)	January 29, 2025
Initial Comments, Minnesota Power	January 29, 2025
Initial Comments, Missouri Basin Municipal Power Agency d/b/a Missouri River Energy Services (MRES)	January 29, 2025
Initial Comments, Otter Tail Power Company (Otter Tail or OTP)	January 29, 2025
Initial Comments, Northern States Power Company d/b/a Xcel Energy (Xcel)	January 29, 2025
Initial Comments, Midwest Renewable Energy Tracking System (M-RETs)	February 5, 2025
Reply Comments, Great River Energy, Rochester Public Utilities, Connexus Energy, Central Municipal Power Agency/Services, Missouri River Energy Services, Minnkota Power Cooperative, Basin Electric Power Cooperative, Minnesota Municipal Utilities Association, Minnesota Municipal Power Agency, East River Electric, Minnesota Rural Electric Association, Otter Tail Power Company, Xcel Energy, Southern Minnesota Municipal Power Agency, and ALLETE Minnesota Power (collectively, "Aligned Utilities")	March 19, 2025
Reply Comments, Basin Electric Power Cooperative (Basin Electric)	March 19, 2025
Reply Comments, CEOs	March 19, 2025

✓ **Relevant Documents**	**Date**
Reply Comments, CMPAS	March 19, 2025
Reply Comments, Connexus	March 19, 2025
Reply Comments, CSG	March 19, 2025
Reply Comments, Department	March 19, 2025
Reply Comments, Google LLC (Google)	March 19, 2025
Reply Comments, Great River Energy	March 19, 2025
Reply Comments, International Union of Operating Engineers Local 49 and North Central States Regional Council of Carpenters (IUOE Local 49 and NCSRC of Carpenters)	March 19, 2025
Reply Comments, Laborers' International Union of North America – Minnesota & North Dakota (LIUNA)	March 19, 2025
Reply Comments, Minnkota	March 19, 2025
Reply Comments, MLIG	March 19, 2025
Reply Comments, Minnesota Pollution Control Agency (MPCA)	March 19, 2025
Reply Comments, MRES	March 19, 2025
Reply Comments, OTP	March 19, 2025
Reply Comments, Partnership on Waste & Energy (Partnership on W&E)	March 19, 2025
Reply Comments, Ramsey/Washington Recycling & Energy Board (Ramsey/Washington R&E)	March 19, 2025
Reply Comments, Xcel	March 19, 2025
Reply Comments, CRS	March 20, 2025
Supplemental Comments, CEOs	April 16, 2025
Supplemental Comments, CMPAS	April 16, 2025
Supplemental Comments, Department	April 16, 2025
Supplemental Comments, EnergyTag	April 16, 2025
Supplemental Comments, LIUNA	April 16, 2025
Supplemental Comments, Minnesota Power	April 16, 2025
Supplemental Comments, Xcel	April 16, 2025
Supplemental Comments, Zero Lab	April 16, 2025
Late-Filed Supplemental Comments, Department	May 23, 2025
Response Comments, Xcel	June 5, 2025

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ACRONYMS

AEC: Alternative Energy Credit/Certificate
CFA: Carbon-Free Allocator
CFS: Carbon-Free Standard
CTT: Clean Transition Tariff
DSES: Distributed Solar Energy Standard
EAC: Environmental Attribute Credit/Certificate
EETS: Eligible Energy Technology Standard
IRP: Integrated Resource Plan
LCA: Life-Cycle Analysis/Assessment
MISO: Midcontinent Independent System Operator
PPA: Power Purchase Agreement
REC: Renewable Energy Credit/Certificate
RES: Renewable Energy Standard
REO: Renewable Energy Objectives
RTO: Regional Transmission Organization
SES: Solar Energy Standard
SPP: Southwest Power Pool

BACKGROUND

I. Executive Summary

In this docket, the question before the Commission is: What requirements should the Commission impose on electric utilities to evaluate their compliance with the carbon-free standard (CFS)?[1] Addressing this issue is another step in the Commission's broader effort to implement 2023 changes to the state's Renewable Energy Objectives (REO) statute.[2]

In these Briefing Papers, the issues before the Commission are divided into three sections: (1) methods for measuring CFS compliance, (2) other proposed requirements and (3) comments outside the scope of this docket.

A. Methods for Measuring CFS Compliance

The Commission received many comments from stakeholders, who were largely in agreement that CFS claims may be substantiated through Renewable Energy Credits (RECs), Alternative Energy Credits (AECs), or equivalent Environmental Attribute Credits (EACs). Proposed decision options focus on, among other things, the following issues:

- May utilities demonstrate compliance with the CFS through other means?
- How can a utility demonstrate compliance using partially-free carbon facilities?
- How can a utility demonstrate compliance using net market purchases?

Finally, Staff proposes reporting requirements for annual REO compliance reports.

B. Other/Supplemental Proposed Requirements

Commenters raised other issues and proposed recommendations that are relevant but not essential for the Commission to establish standards for measuring CFS compliance. Broadly, these include, among others:

- Hourly matching for CFS compliance, in resource plan modeling, and data reporting
- Shelf life of RECs
- Residual mix accounting in net market purchases

C. Comments Outside the Scope of this Docket

Commenters also raised issues that Staff believe would be better addressed in future proceedings or in a separate docket. These include (1) existing contracts and off-ramps, (2) requiring utilities to assess the ratepayer impacts of CFS compliance, (3) considering whether RECs from biomass and solid wastes facilities may be used for CFS compliance, and (4) the

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[1] Minn. Stat. § 216B.1691, subd. 2g.

[2] Minn. Stat. § 216B.1691.

health impacts of burning biomass.

II. Applicable Statute

Minn. Stat. § 216B.1691, subd. 2d sets forth the Commission's oversight in evaluating and determining utility compliance with the carbon-free standard.

> **Subd. 2d. Commission order.**
> (a) The commission shall issue necessary orders detailing the criteria and standards used to: (1) measure an electric utility's efforts to meet the standards under subdivisions 2a, 2f, and 2g; and (2) determine whether the utility is achieving the standards.
> (b) In the order under paragraph (a), the commission shall include criteria and standards that: (1) protect against undesirable impacts on the reliability of the utility's system and economic impacts on the utility's ratepayers and that consider technical feasibility; and (2) require the commission to allow for partial compliance with subdivision 2g from:
> (i) electricity generated from facilities that utilize carbon-free technologies for electricity generation, but only for the percentage that is carbon-free; and
> (ii) an electric utility's annual purchases from a regional transmission organization net of the electric utility's sales to the regional transmission organization, but only for the percentage of annual net purchases that is carbon-free, which percentage the commission must calculate based on the regional transmission organization's systemwide annual fuel mix or an applicable subregional fuel mix.

Minn. Stat. § 216B.1691, subd. 3 governs utility reporting.

> **Subd. 3. Utility plans filed with commission.**
> (a) Each electric utility shall report on its plans, activities, and progress with regard to the standard obligations under this section in its filings under section 216B.2422 or in a separate report submitted to the commission every two years, whichever is more frequent, demonstrating to the commission the utility's effort to comply with this section. In its resource plan or a separate report, each electric utility shall provide a description of:
> (1) the status of the utility's renewable energy mix relative to the standard obligations;
> (2) efforts taken to meet the standard obligations;
> (3) any obstacles encountered or anticipated in meeting the standard obligations;

(4) potential solutions to the obstacles;
(5) the number of Minnesotans employed to construct facilities designed to meet the utility's standard obligations under this section;
(6) efforts taken to retain and retrain workers employed at electric generating facilities that the utility has ceased operating or designated to cease operating for new positions constructing or operating facilities used to meet a utility's standard obligation;
(7) the impacts of facilities designed to meet the utility's standard obligations under this section on environmental justice areas;
(8) efforts made to increase the diversity of both the utility's workforce and vendors; and
(9) for an electric utility utilizing renewable energy credits to satisfy any portion of the electric utility's obligations under this section, the following information:

(i) the name and location of energy facilities that generated the energy associated with the credits;
(ii) the dates when the energy associated with the credits was generated;
(iii) the type of fuel that generated the energy associated with the credits; and
(iv) whether the energy associated with the credits was purchased by the utility purchasing the credits.

(b) The commissioner shall compile the information provided to the commission under paragraph (a), and report to the chairs of the house of representatives and senate committees with jurisdiction over energy and environment policy issues as to the progress of utilities in the state, including the progress of each individual electric utility, in increasing the amount of renewable energy provided to retail customers, with any recommendations for regulatory or legislative action, by January 15 of each odd-numbered year.

III. CFS Docket Background

H.F. No. 7 became effective on February 7, 2023, amending Minn. Stat. § 216B.1691 (the Renewable Energy Objectives or "REO" statute). These amendments included changes to Minnesota's existing Renewable Energy Standard (RES) – which was renamed to the Eligible Energy Technology Standard (EETS) – and the introduction of the state's CFS.

To address these changes and ensure that the Commission met its statutory obligations, Staff

opened the instant docket, Docket No. E-999/CI-23-151 (CFS Docket), and structured it around four rounds of comments with each round tackling specific issues arising from amendments made to the REO statute. The following shows the current timeline of those rounds:

Table 1: Docket History and Timeline

Round	Content	Comment Period Date	Agenda Meeting Date	Order Date
1	Changes to RES and SES	Initial: August 2, 2023 Reply: August 18, 2023	October 19, 2023	December 6, 2023
1.5	Additional clarifications: changes to RES and SES	Initial: January 19, 2024 Reply: February 7, 2024	March 14, 2024	April 12, 2024
2	New and Amended Terms	Initial: June 28, 2024 Reply: July 24, 2024	September 26, 2024	November 7, 2024
2.5	Reconsideration/ Clarification of Round 2 Order	Petition: November 27, 2024 Answer to Petition: December 6, 2024	January 16, 2025	January 23, 2025
3	CFS Compliance	Initial: January 29, 2025 Reply: March 19, 2025 Supplemental: April 16, 2025	July 17, 2024	TBD
4	Off Ramp Process[3]	Q3 2025	Q4 2025	TBD

In Round 1, the Commission's December 6, 2023 Order:

- Specified which utilities are subject to the EETS (formerly RES) and CFS under the revised definition of "electric utility;"
- Directed the Executive Secretary to open an additional comment period to develop the record on specific remaining questions ("Round 1.5");
- Clarified certain reporting requirements;
- Specified how utilities becoming subject to Minn. Stat. § 216B.1691 or becoming no longer subject to Minn. Stat. § 216B.1691 should notify the Commission; and
- Made provisions concerning large hydroelectric facilities and utilities with members or customers in the Western Area Power Administration.

In Round 1.5, the Commission's April 12, 2024 Order clarified certain remaining questions from Round 1.

In Round 2, the Commission's November 7, 2024 Order:

[3] Staff notes that the Round 4 timeline will be delayed by at least one quarter.

- Clarified how "environmental justice area" should be interpreted;
- Opened Docket No. E-999/CI-24-352, *In the Matter of a Commission Investigation into a Fuel Life-Cycle Analysis Framework for Utility Compliance with Minnesota's Carbon-Free Standard* (LCA Docket or Life-Cycle Analysis Docket). This was done to develop a record on the carbon impacts of complex fuels such as hydrogen and biomass, and the Commission intends to rule on this docket by the end of 2025.
- Determined that further record development was needed concerning the calculation and definition of net market purchases, both in the CFS Docket and in the newly created LCA Docket. Pending the outcome of these investigations, the Commission provisionally directed utilities, in their filings under the CFS and in resource plans under Minn. Stat. § 216B.2422, to do the following:
    - Calculate the percentage of carbon-free market purchases using an applicable regional transmission organization subregion—using annual energy fuel mix data—as practicable.[4]
    - Calculate the percentage of carbon-free energy, when a utility purchases energy from a specified resource such as in the context of a bilateral contract or power purchase agreement, based on the percentage of carbon-free energy generated by that resource.

In Round 2.5, the Commission's January 23, 2025 Order denied the Clean Energy Organizations' (CEOs') Petition for Clarification and Reconsideration on the November 7, 2024 Order.

The current Briefing Papers cover Round 3, which covers CFS compliance. Staff asked the following questions of commenters:

1. When and how should utilities report preparedness for meeting upcoming CFS requirements?
2. By which criteria and standards should the Commission measure an electric utility's compliance with the CFS?
3. What considerations should the Commission take into account regarding the double counting of Renewable Energy Credits (RECs) to meet multiple requirements?
4. How should net market purchases be counted towards CFS compliance?
5. Are there other issue or concerns related to this matter?

[4] Staff notes that as this directive is worded, utilities participating in the Midcontinent Independent System Operator (MISO) will calculate net market purchases using MISO North data, whereas utilities participating in Southwest Power Pool (SPP) will use systemwide data. This has to do with what data sources are currently available. For a further discussion of this, *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Minnesota Public Utilities Commission Staff Briefing Papers at 75-77 (September 12, 2024) (hereinafter "Staff September 12th Briefing Papers").

IV. Current REO Standards

A. The Eligible Energy Technology Standard (EETS)

The EETS (formally RES) is found in Subd. 2a. of the REO Statute and requires all electric utilities to generate or procure electricity from "eligible energy technologies" to cover a percentage of their total retail electric sales in a given year. Broadly, eligible energy technologies include solar, wind, certain hydroelectric and biomass facilities, and hydrogen generated from eligible energy technologies.[5]

> **Subd. 2a. Eligible energy technology standard.**
> Each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from an eligible energy technology that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated:
>
> (1) 2012 12 percent
>
> (2) 2016 17 percent
>
> (3) 2020 20 percent
>
> (4) 2025 25 percent
>
> (5) 2035 55 percent.

B. The Solar Energy Standard (SES)

The SES, found in Subd. 2f of the REO statute, requires public utilities[6] to generate or procure solar electricity so that by the end of 2020, at least 1.5% of the utility's total retail electric sales is generated by solar energy. For public utilities with more than 200,000 retail customers, at least 10% of the 1.5% goal must be met by solar with a nameplate capacity of 40kW or less. This is often referred to as the "small-scale carve out" requirement.

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[5] Specifically, per Minn. Stat. §216B.1691, subd.1(c), eligible energy technologies include solar, wind, hydroelectric with a capacity of less than 100 MW or 100 MW or more provided the facility is in operation as of February 8, 2023, hydrogen generated from eligible energy technologies, or biomass. Biomass includes, without limitation: landfill gas; an anaerobic digester system; the predominantly organic components of wastewater effluent, sludge, or related by-products from publicly owned treatment works, but not including incineration of wastewater sludge to produce electricity; and, except as provided in subdivision 1a, an energy recovery facility used to capture the heat value of mixed municipal solid waste or refuse-derived fuel from mixed municipal solid waste as a primary fuel.

[6] Public utilities currently include Xcel Energy, Minnesota Power, and Otter Tail Power.

C. The Distributed Solar Energy Standard (DSES)

Like the SES, the DSES (Subd. 2h) applies only to public utilities, but requires that by 2030, between one and three percent[7] of the utility's annual retail electric sales be generated by solar systems that: have a capacity of ten MW (10,000 kW) or less; are connected to the utility's Minnesota distribution system, and; are constructed or procured after August 1, 2023.

D. The Carbon-Free Standard

The CFS prescription is found in Subd. 2g. and requires all electric utilities[8] to generate or procure the equivalent of 100% of their Minnesota electric retail sales load with carbon-free energy by the end of 2040. Notably, the statutory language of the CFS (2g) is nearly identical to the EETS (2a).

> **Subd. 2g. Carbon-free standard.**
> In addition to the requirements under subdivisions 2a and 2f, each electric utility must generate or procure sufficient electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from carbon-free energy technologies that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota by the end of the year indicated:
>
> (1) 2030: 80 percent for public utilities, 60 percent for other electric utilities
> (2) 2035: 90 percent for all electric utilities
> (3) 2040: 100 percent for all electric utilities

V. Commission Implementation of Standards

A. Evolution of REO Statute

Minn. Stat. § 216B.1691, the Renewable Energy Objectives, was created in 2001. The REO Statute has been modified several times over the years, with significant changes in 2003, followed by the introduction of the RES (now EETS) in 2007, additional reporting requirements

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[7] The percent of annual retail electric sales that must be generated by solar energy generating systems varies based on the size of the utility: At least 200,000 retail customers = 3%, At least 100,000 retail customers but fewer than 200,000 = 3%, Fewer than 100,000 retail customers = 1%.

[8] Note that the Commission's December 6, 2023 Order specified exactly which utilities are beholden to CFS requirements.

in 2011, the SES in 2013, and most recently, major revisions in 2023, including the introduction of the distributed solar energy standard (DSES) and the carbon-free standard (CFS).

B. Implementation of REO

The Commission's efforts to implement the "modern" REO Statute – introduction of the RES and onward – occurred in Docket No. E-999/CI-03-869,[9] through which, the Commission, among other things:

- Confirmed the initial list of "electric utilities" subject to the REO Statute.[10]
- Clarified that out-of-state generation may be used to meet REO objectives so long as those facilities are used to serve Minnesota customers.[11]
- Clarified that, in meeting REO objectives, utilities may not include generation purchased under green pricing programs.[12]
- Found that, at the time, it was not in the public interest to assign multiple RECs to any one eligible technology or fuel.[13]
- Determined that compliance would be measured on a calendar year basis by retiring RECs within the Midwest Renewable Energy Tracking System (M-RETS),[14] and affirmed the information to be included in both annual,[15] and biennial[16,17] compliance reports.
- Clarified that a petition to modify or delay the REO[18] must include: a discussion of the reasons for concluding that compliance cannot be achieved by buying RECs; a plan for future compliance, and the time frame within which the petitioner requests

[9] In the Matter of Commission Consideration and Determination on Compliance with Renewable Energy Obligations and Renewable Energy Standards.

[10] June 1, 2004, Initial Order Detailing Criteria and Standards for Determining Compliance with Minn. Stat. § 216B.1691 and Requiring Customer Notification by Certain Cooperative, Municipal, and Investor-Owned Distribution Utilities, Docket No. E-999/CI-03-869, Order Paragraph 1.

[11] Id. at Order Paragraph 4.

[12] August 13, 2004, Order After Reconsideration, Docket No. E-999/CI-03-869, Order Paragraph 1.

[13] October 19, 2004, Second Order Implementing Minn. Stat. §216B.1691, Opening Docket to Investigate Multi-State Program for Tracking and Trading Renewable Credits, and Requesting Periodic Updates from Stakeholder Group, Docket Nos. E-999/CI-03-869 and E-999/CI-04-1616, Order Paragraph 1.

[14] December 3, 2008, Third Order Detailing Criteria and Standards for Determining Compliance Under Minn. Stat. §216B.1691 and Setting Procedures for Retiring Renewable Energy Credits, Order Paragraphs 1 and 3.

[15] Id. at Order Paragraphs 6 and 7.

[16] November 12, 2008, Order Setting Filing Requirements and Clarifying Procedures, Docket No. E-999/CI-03-869, Order Paragraph 8.

[17] May 28, 2013, Order Finding Utilities in Compliance with Minn. Stat. § 216B.1691 and Modifying Biennial Reporting Procedures, Docket Nos. E-999/M-12-958, E-999/CI-03-869, E-999/PR-11-189, and E-999/PR-12-334, Order Paragraph 5.

[18] As permitted by Minn. Stat. § 216B.1691, subd. 2b.

Commission action.[19,20]

- Determined that the REO's impact on rates would be best handled through utilities' rate cases, and that the annual reliability reporting requirements[21] would adequately apprise the Commission and stakeholders of any utility-specific drops in reliability.[22] The Commission recognized that not all utilities subject to the REO file rate cases, and stated that it would accept voluntary filings on the rate impacts of the REO in utilities' biennial compliance reports.

While there have been continuous changes over time regarding the content and timing of utilities' compliance reporting, including some made in this docket, the Orders found in Docket No. E-999/CI-03-869 have served as the foundation for REO compliance as the statute has changed over time.

C. Tracking and Verifying Compliance

Utilities comply with the REO through the retirement of RECs, where one REC is equivalent to one MWh of electricity generated by a qualifying technology.

To track and verify compliance with the REO, the Commission ordered the establishment of an independent tracking system to certify, verify, and implement compliance with the REO[23] and created a docket to investigate the establishment of a multi-state tracking and trading program for RECs.[24] These efforts ultimately led to the creation of M-RETS. In an October 9, 2007 Order, the Commission approved M-RETS as the renewable credit tracking system used for REO compliance and required all utilities subject to the REO to participate in the system.[25] Later, through separate Orders, the Commission further clarified that all generating units used to meet the REO must be registered in M-RETS,[26] that all entities covered under the REO statute

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[19] Minn. Stat. 216B.1691, subd. 2b(c) requires that inability to meet the standard must include a plan for future compliance.

[20] March 19, 2010 Order Clarifying Criteria and Standards for Determining Compliance Under Minn. Stat. § 216B.1691, Docket No. E-999/CI-03-869, Order Paragraph 5.

[21] Contained in Minnesota Rules Chapter 7826

[22] March 19, 2010 Order Clarifying Criteria and Standards for Determining Compliance Under Minn. Stat. § 216B.1691, Docket No. E-999/CI-03-869, Order Paragraph 7.

[23] June 1, 2004, Initial Order Detailing Criteria and Standards for Determining Compliance with Minn. Stat. § 216B.1691 and Requiring Customer Notification by Certain Cooperative, Municipal, and Investor-Owned Distribution Utilities, Docket No. E-999/CI-03-869, Order Paragraph 12.

[24] October 19, 2004, Second Order Implementing Minn. Stat. § 216B.1691, Opening Docket to Investigate Multi-State Program for Tracking and Trading Renewable Credits, and Requesting Periodic Updates from Stakeholder Group, Docket Nos. E-999/CI-03-869 and E-999/CI-04-1616, Order Paragraph 2.

[25] October 9, 2007 Order Approving Midwest Renewable Energy Tracking System (M-RETS) Under Minn. Stat. Minn. Stat. § 216B.1691, subd.4(d) and Requiring Utilities to Participate in M-RETS, Docket No. E-999/CI-04-1616, Order Paragraphs 1 and 2.

[26] December 18, 2007, Order Establishing Initial Protocols for Trading Renewable Energy Credits, Docket No. E-999/CI-03-869, Order Paragraph 5.

must retire RECs specifically within the M-RETS system,[27] that only RECs recorded and tracked through M-RETS may be used for compliance with the REO,[28] and that compliance will be measured on a calendar year basis through the transfer and retirement of RECs.[29]

These RECs can be generated by utility-owned assets or be purchased by the utility for compliance. The flexibility to allow purchased or owned RECs rewards those who can build and operate renewables at a lower cost, providing checks and balances for ratepayers and accountability to utilities. When purchased, RECs can be coupled with electricity ("bundled RECs") or purchased as a standalone "unbundled" asset.

While the Commission has historically used RECs, other types of serialized trackable credits do exist, such as Alternative Energy Credits/Certificates (AECs) which are used to track environmental attributes for sources of generation that may not be considered "renewable," such as nuclear. All types of serialized trackable credits are covered under the broader term of Environmental Attribute Credit (EAC). These credits/certificates[30] track information about the electricity being generated, including the facility, facility location, and date of generation. These unique serialized accounting mechanisms allow the EAC holder to legally claim the environmental attributes associated with the underlying energy – such as the claim that the energy is carbon-free – and prevent others from claiming the same attributes for the same MWh. While "REC" is the more familiar term than "EAC"—and lends itself better to spoken language—EAC is generally thought to be a preferred term because it encompasses both renewable RECs and carbon-free-but-not-renewable AECs.

RECs retired to substantiate compliance with the EETS or the SES may also count toward CFS compliance, so long as the facility generating the credit qualifies as "carbon-free." However, the legislature did not extend this dual eligibility to the DSES, and so through its June 26, 2024 Order Clarifying implementation of the Distributed Solar Energy Standard, the Commission affirmed utilities' ability to count RECs retired for the DSES toward any other REO standard.[31]

D. REC Shelf Life

While establishing protocols for the tracking, retiring, and trading of RECs in 2007, the Commission also adopted a four year REC shelf life, equal to the year of generation plus four years following the year of generation.[32] Only RECs retired before the end of their shelf life are

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[27] December 3, 2008, Third Order Detailing Criteria and Standards for Determining Compliance Under Minn. Stat. § 216B.1691 and Setting Procedures for Retiring Renewable Energy Credits, Order Paragraph 1.

[28] Id. at Order Paragraph 8.

[29] Id. at Order Paragraphs 1 and 3.

[30] Staff uses the term "credit" in these Briefing Papers, since credits is the term found in the REO Statute, appears to be historically favored by the Commission, and is broader in concept than "certificate."

[31] June 26, 2024, Order Clarifying Implementation of Distributed Solar Energy Standard, Docket No. E-002, E-015, E-017/CI-23-403, Order Paragraph 11.

[32] December 18, 2007, Order Establishing Initial Protocols for Trading Renewable Energy Credits, Docket No. E-999/CI-03-869, Order Paragraph 1.

eligible to be used for compliance. This Commission-created REC shelf life has been extended over time to include RECs retired for green pricing programs[33] and the SES.[34] Notably, when establishing the reporting requirements for the SES, the Commission ordered that the shelf life of RECs generated from facilities that were designed to meet the SES would not begin until 2020, when utilities were first expected to comply with the SES. The Commission noted that this extended shelf life for RECs generated from facilities before 2020 would ensure that utilities were not penalized for acquiring solar energy well ahead of the initial compliance date of 2020.[35]

E. SES and DSES Preparedness Reports

Both the SES and DSES were introduced at a time in which annual REO compliance reports were well established. In the years leading up to the first compliance period for these standards – 2020 for the SES and 2030 for the DSES – the Commission ordered utilities to provide information about their performance toward meeting each standard on an annual basis.[36,37] Staff has named this forward-looking, pre-compliance reporting as "preparedness reports" as they ultimately are intended to assess whether a utility is on track to comply with a standard before the start of statutory compliance periods. While SES preparedness reports were provided as a standalone filing, DSES preparedness reports have been incorporated into the REO compliance reporting template. The most recent preparedness report requirements (for DSES), included the following:

- Annual Minnesota retail sales from the previous calendar year.
- The total Minnesota retail sales for customers excluded from the DSES requirement.
- Annual qualifying solar generation on the utilities' system for the previous calendar year, including the total number of units registered in M-RETS to that utility and Solar-RECs (S-RECs) generated in the past year from those units.
- From 2025-2030, utilities must also report the following:
    - The status of process implementation, project procurements and construction.
    - Any considerations, such as those outlined in Minn. Stat. § 216B.1691, subd. 2b, that may create challenges with achieving compliance, and which under Minn. Stat. § 216B.1691, subd. 2h(f), may allow the Commission to modify or delay implementation.
- Estimated solar capacity and energy requirements needed to meet the DSES in 2030.
- A short summary of ongoing efforts to obtain solar energy, including a brief summary of the anticipated mix of project sizes.

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[33] Id. at Order Paragraph 3.

[34] April 25, 2014, Order Clarifying solar Energy Standard Requirements and Setting Annual Reporting Requirements, Docket No. E-999/CI-13-542, Order Paragraphs 1 and 2.

[35] Id. at 3.

[36] Id. at Order Paragraph 4.

[37] June 26, 2024, Order Clarifying Implementation of Distributed Solar Energy Standards, Docket No. E-002, E-015, E-017/CI-23-403, Order Paragraph 8.

F. Annual and Biennial Compliance Reports

Currently, REO compliance reports are provided by utilities by June 1st each year in YR-12 dockets (for example, in 2025 the REO compliance docket number is 25-12). All RECs used for compliance must be retired by May 1st in M-RETS retirement accounts created and managed by Commission Staff. In contrast to the forward-looking preparedness reports mentioned above, these compliance reports focus on looking backward and verifying actual compliance.

Commission Staff update the compliance reporting template each year and upload it onto the Minnesota Department of Commerce's website.[38] During the template revision process, Commission Staff apply minor modifications to the template, either adding or removing questions from the template depending on if it is a biennial reporting year or not,[39] and add additional content if ordered by the Commission. Along with these compliance reports, utilities are required to provide spreadsheets detailing RECs retired for compliance to fulfill the requirements established by Minn. Stat. § 216B.1691, subd.3(a)(9). As noted above, the DSES preparedness reports are also included in the REO compliance reports.[40]

[38] https://mn.gov/commerce-stat/xls/25-12-reporting-template.xlsx

[39] Compliance questions specific to biennial reports are outlined in Minn. Stat. § 216B.1691, subd.3.

[40] Commission Staff note that the SES preparedness reports were submitted as a separate form.

DISCUSSION

VI. Threshold Issues for Commission Consideration

Commission must determine how utilities demonstrate compliance with the CFS.

Credit tracking. Commenters agree that utilities may demonstrate compliance by retiring RECs, AECs, or equivalent EACs tracked by M-RETS but disagree about whether utilities may demonstrate compliance using other methods as well. They seek guidance on the following:

- May utilities use other means of demonstrating CFS compliance, even if those means increase the risk that some environmental attributes are double-claimed?

Partially carbon-free facilities. Commenters raised various questions about how partially carbon-free facilities can help a utility comply with the CFS.

- Should the Commission defer these questions to the pending Life-Cycle Analysis Docket?
- If not, should the Commission adopt the Department's detailed proposal in this docket?
- If not, should the Commission begin working with M-RETS to permit the tracking of partial credits awarded to partially carbon-free facilities?

Net market purchases. Commenters seek guidance on the following:

- When a utility buys energy from the wholesale market, may the utility calculate the amount of carbon-free energy it acquires based on the share of carbon-free energy in the relevant wholesale market, even if the utility acquires no credits as part of its wholesale purchase?

Reporting Requirements. Finally, Commission staff propose adopting new reporting requirements, and revising old ones, to enable utilities to demonstrate CFS compliance.

A. Credit Tracking

Many commenters supported the retirement of RECs, AECs, or equivalent EACs through M-RETs as the primary means of CFS claims substantiation. Commenters were also in agreement that the REO permits utilities to use RECs towards multiple Standards.

Carbon Solutions Group (CSG),[41] Center for Resource Solutions (CRS),[42] Central Minnesota

[41] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Carbon Solutions Group Initial Comments at 2 (January 29, 2025) (hereinafter "CSG Initial").

[42] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Center for Resource Solutions Initial Comments at 4 (January 29, 2025) (hereinafter "CRS Initial").

Power Agency/Services (CMPAS),[43] Clean Energy Organizations (CEOs),[44] the Department of Commerce's Division of Energy Resources (Department),[45] EnergyTag,[46] Great River Energy,[47] Laborers' International Union of North America—Minnesota and North Dakota (LIUNA),[48] Midwest Renewable Energy Tracking Systems (M-RETS),[49] Minnesota Power,[50] Minnkota Power Cooperative (Minnkota),[51] Missouri Basin Municipal Power Agency d/b/a Missouri River Energy Services (MRES),[52] Northern States Power Company d/b/a Xcel Energy (Xcel),[53] Otter Tail Power (OTP),[54] and Ramsey/Washington Recycling & Energy Board (Ramsey/Washington

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[43] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Central Minnesota Power Agency/Services Initial Comments at 4 (January 29, 2025) (hereinafter "CMPAS Initial").

[44] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Clean Energy Organizations Reply Comments at 7 (March 19, 2025) (hereinafter "CEOs Reply").

[45] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Department of Commerce, Division of Energy Resources Initial Comments at 5-7 (January 29, 2025) (hereinafter "Department Initial").

[46] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, EnergyTag Supplemental Comments at 12 (April 16, 2025) (hereinafter "EnergyTag Supplemental").

[47] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Great River Energy Initial Comments at 2 (January 29, 2025) (hereinafter "Great River Energy Initial").

[48] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Laborers' International Unition of North America—Minnesota and North Dakota Reply Comments at 1 (March 19, 2025) (hereinafter "LIUNA Reply").

[49] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Midwest Renewable Energy Tracking Systems Initial Comments at 4 (February 5, 2025) (hereinafter "M-RETS Initial").

[50] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Minnesota Power Initial Comments at 2 (January 29, 2025) (hereinafter "Minnesota Power Initial").

[51] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Minnkota Power Cooperative, Inc. Initial Comments at 2 (January 29, 2025) (hereinafter "Minnkota Initial").

[52] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Missouri River Energy Services Initial Comments at 3 (January 29, 2025) (hereinafter "MRES Initial").

[53] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Northern States Power Company d/b/a Xcel Energy Initial Comments at 5 (January 29, 2025) (hereinafter "Xcel Initial").

[54] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Otter Tail Power at 4-5 (January 29, 2025) (hereinafter "OTP Initial").

R&E)[55] were supportive of REC retirement through M-RETS as a means for substantiating CFS claims.

These groups also noted the need for the Commission to approve the use of EACs for resources that are carbon-free but not renewable (i.e., generation that is CFS-eligible but not EETS-eligible), such as nuclear energy. For this purpose, commenters supported the use of Alternative Energy Credits (AECs) or an equivalent Environmental Attribute Credit (EAC). **(Decision Option 1)** AECs are similar to RECs in that they are tracked by M-RETS, have unique serial tracking numbers, and are each associated with 1 MWh of electricity generated; EACs are the broader umbrella term encompassing RECs and AECs.

Basin Electric Power Cooperative (Basin),[56] CMPAS,[57] Connexus,[58] CRS,[59] CSG,[60] the Department,[61] Great River Energy,[62] Minnesota Power,[63] Minnkota,[64] MRES,[65] OTP,[66] Ramsey/Washington Recycling & Energy,[67] and Xcel[68] agreed that the dual application of RECs towards multiple REO Standards is statutorily permissible. Minn. Stat. § 216B.1691, subd. 4(a) provides that a REC:

> **Subd. 4. Renewable energy credits.**
> (a) … be used only once, except that a credit may be used to satisfy both the carbon-free energy standard obligation under subdivision 2g and either the renewable energy standard obligation under

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[55] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Ramsey/Washington Recycling & Energy Board Reply Comments at 2-3 (March 19, 2025) (hereinafter "Ramsey/Washington R&E Reply").

[56] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Basin Electric Power Cooperative Reply Comments at 2-3 (March 19, 2025) (hereinafter "Basin Reply").

[57] CMPAS Initial at 5-6.

[58] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Connexus Energy Initial Comments at 2 (January 29, 2025) (hereinafter "Connexus Initial").

[59] CRS Initial at 4.

[60] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Carbon Solutions Group Reply Comments at 7 (March 19, 2025) (hereinafter "CSG Reply").

[61] Department Initial at 21.

[62] Great River Energy Initial at 2.

[63] Minnesota Power Initial at 2-4.

[64] Minnkota Initial at 3.

[65] MRES Initial at 3.

[66] OTP Initial at 4-5.

[67] Ramsey/Washington R&E Reply at 2.

[68] Xcel Initial at 8-9.

> subdivision 2a or the solar energy standard obligation under subdivision 2f, if the credit meets the requirements of each subdivision.

Commenters noted that the plain language of the REO statute already clarifies that RECs can be: retired to meet only a utility's CFS requirements, retired to meet only a utility's EETS/SES requirements, or retired to meet both a utility's CFS requirements and *either* its EETS *or* SES requirements. CMPAS also observed that the Commission has explicitly permitted the dual use of RECs for meeting both the DSES and any other standard obligation required by Minn. Stat. § 216B.1691.[69]

But the parties disagreed on the following:

- May utilities use other means of demonstrating CFS compliance, even if those means increase the risk that some environmental attributes are double-claimed?

1. Commenter Positions

a. Flexibility in Compliance

Minnkota,[70] Minnesota Power,[71] and OTP[72] argued that while REC retirement is one acceptable form of CFS substantiation, utilities should be allowed flexibility in demonstrating compliance. **(Decision Option 2)** These commenters noted that some carbon-free resources may not produce a REC, which creates a need for such flexibility. Minnkota interpreted the REO Statute's noncompliance language to be supportive of such flexibility, since the remedies are varied: "if the commission finds noncompliance, it may order the electric utility to construct facilities, purchase energy generated by eligible energy technology, purchase renewable energy credits, or engage in other activities to achieve compliance."[73] Minnkota further argued that renewable energy credits may be used to satisfy the CFS, but are not the only manner of demonstrating compliance due to the statute's use of the phrase "an electric utility may utilize renewable energy credits…"[74] These parties provided no alternative compliance recommendation for the Commission's consideration.

LIUNA submitted comments generally noting that when the CFS legislation was being passed, the flexibility of the statute was one of the main selling points for investor-owned and

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[69] CMPAS Initial at 5-6, referencing Commission's June 26, 2024 Order Clarifying Implementation of Distributed Solar Energy Standard ("DSES Order") in Docket No E002, E015, E017/CI-23-403 at 14.

[70] Minnkota Initial at 2.

[71] Minnesota Power Initial at 2.

[72] OTP Initial at 4-5.

[73] Minn. Stat. § 216B.1691, subd. 7.

[74] Minn. Stat. § 216B.1691, subd. 4(b).

cooperative utilities.[75]

Initially, CMPAS recommended that utilities be allowed flexibility in demonstrating compliance, pointing to its potential inability to retire environmental attribute credits associated with a specific Power Purchase Agreement (PPA) in which CMPAS offtakes less than two percent of the Point Beach Nuclear Plant Units 1 and 2 in Wisconsin.[76] CMPAS argued that because it is a small off taker, it 1) does not have access to revenue grade meter reads and 2) cannot ask the plant owners to use any newly emerging certificates or verification methods, particularly for the remaining 98% of power. CMPAS therefore noted that it may need to be able to report compliance through other means such as PPA billing statements or metered generation data.

The Department countered that Point Beach was in fact registered in M-RETS, and that a nuclear facility is likely to issue AECs, since these have a market value.[77] The Department further noted that it is incumbent upon utilities to ensure their PPAs include AECs, should the utility be planning on using the power for that PPA towards CFS compliance; alternatively, the Department noted, the utility could purchase unbundled RECs/AECs.

In Supplemental Comments, CMPAS confirmed it will receive AECs under this PPA and withdrew its recommendation.[78]

b. Claims-based Compliance Only

CEOs,[79] CRS,[80] CSG,[81] the Department,[82] and M-RETs[83] noted that EAC retirement through a tracking system such as M-RETs is the best way to prevent double-counting of environmental attributes, and that when utilities are permitted to demonstrate compliance through other means, the potential for double-counting increases. CRS argued that permitting a utility to claim *any* amount of power towards CFS compliance without having to obtain and retire the

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[75] LIUNA Reply at 1.

[76] CMPAS Initial at 4-5.

[77] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Minnesota Department of Commerce – Division of Energy Resources Reply Comments at 18 (March 19, 2025) (hereinafter "Department Reply").

[78] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Central Minnesota Power Agency/Services Supplemental Comments at 4 (April 16, 2025) (hereinafter "CMPAS Supplemental").

[79] CEOs Reply at 7.

[80] CRS Initial at 2-3.

[81] CSG Initial at 4-5.

[82] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Minnesota Department of Commerce – Division of Energy Resources Supplemental Comments at 47 (April 16, 2025) (hereinafter "Department Supplemental").

[83] M-RETS Initial at 4.

corresponding RECs allows that utility to claim avoided emissions that are already the basis of someone else's emissions reduction claim, noting: "Procuring and retiring RECs creates an indelible chain of custody establishing the purchaser's exclusive ownership of the generation attributes of the power from which the REC was derived. No other method can verify exclusive ownership of these attributes."[84] EnergyTag was also generally supportive of EAC retirement as the means by which to substantiate carbon-free energy claims.[85]

M-RETS cited the EPA's definition of double-counting as "when two different parties claim the same environmental benefits from the same generated" power.[86] CSG drew a further distinction between double *counting* and double *claiming*:

- **Double counting** is when two separate entities use the same REC to make separate energy-based claims. This could occur, for example, if multiple parties are sold the same REC but use two different tracking systems. Another example might be if a utility used the same REC both to meet its RES requirements and in a sale in its voluntary green pricing program.

- **Double claiming** is when a) one entity makes a MWh-based emissions claim substantiated by an unbundled REC retirement, and b) another entity makes an emissions claim based on the same MWh but substantiated by generation or sales data for the underlying electricity. In this case, two different datasets, reflecting the same single MWh claim, are being used to substantiate two separate MWh-based claims. This could occur, for example, if a facility with a power purchase agreement for on-site solar claims to be using renewable electricity, while at the same time, the system owner is selling the RECs to a utility to meet its RES requirements.

CSG listed a number of problems associated with double counting and double claiming, including market distortion, the potential for greenwashing, misinformed policymakers and ratepayers, and the undermining of Minnesota statutory goals.[87] CSG identified the most critical issue to address concerning double-claiming is accurately accounting for unbundled REC sales; when RECs are unbundled from the underlying electricity, that electricity should be considered "null power," *not* renewable or carbon-free. Staff notes that this concept is especially important in PPAs and in calculating fuel mixes.

To address these potential double-counting and double-claiming issues, CEOs,[88] CRS,[89] CSG,[90]

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84 CRS Initial at 3.

85 EnergyTag Supplemental at 12.

86 M-RETS Initial at 3.

87 CSG Initial at 2.

88 CEOs Reply at 7.

89 CRS Initial at 2-3.

90 CSG Initial at 4-5.

the Department,[91] and M-RETS[92] recommended that EAC retirement be the exclusive way to demonstrate CFS compliance. **(Decision Option 1 only)** CSG bolstered these recommendations by recommending that double counting and double claiming be expressly prohibited, and that M-RETS serve as the sole tracking system for CFS compliance.[93]

2. Staff Analysis

With the information provided by commenters, Staff observes that the term "double-counting" is not the ideal term to use when describing a utility using the same REC to meet multiple Standards under the REO. Better terms to describe this would include the word "dual," such as "dually eligible" RECs or "dual purpose" RECs.

- **Dual use/purpose/eligibility:** When a single REC/AEC/EAC is permissibly used to meet multiple standards.

Staff also notes that CSG recommended that M-RETS serve as the sole tracking system for CFS compliance, but as discussed in the Background section above, the Commission has previously decided that M-RETS serve as the sole tracking system for REO compliance. Staff also notes that CSG's recommendation to expressly prohibit double counting and double claiming will be the *de facto* provision, should the Commission adopt **Decision Option 1 only.**

Staff notes that Minnkota argued that RECs are not the only manner of demonstrating compliance due to the statute's use of the phrase "an electric utility may utilize renewable energy credits…"[94] However, this part of the statute applies to all REO Standards, and the Commission has been using REC retirements as the exclusive method to verify EETS (formally RES) compliance for seventeen years. Staff concludes the use of the word "may" does not preclude a Commission requirement for REC retirement.

Staff also notes that Minnkota's concern that some carbon-free facilities may not produce RECs could be mitigated by **Decision Option 1.**

Finally, Staff notes that no advocate provided a ratepayer impact analysis to defend either side of this discussion. Staff notes that the Minnesota Large Industrial Customers (MLIG) did request utilities be required to report information on the cost of complying with the CFS, but this request did not contemplate an examination of comparative costs for flexibility versus

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91 Department Supplemental at 47. The Department indicates that it would be open to a very narrow circumstance in which EACs do not need to be retired to substantiate CFS compliance: this would involve a very robust residual mix accounting process. However, the Department still found EAC retirement to be the preferable means for obligated utilities to demonstrate CFS compliance.

92 M-RETS Initial at 4.

93 CSG Reply at 3.

94 Minn. Stat. § 216B.1691, subd. 4(b).

exclusivity in compliance substantiation.[95]

Staff has structured Decision Options in the following manner:

Decision Option 1: The Commission authorizes utilities to demonstrate compliance with the Carbon-Free Standard by retiring Renewable Energy Credits, Alternative Energy Credits, or equivalent Environmental Attribute Credits registered with the Midwest Renewable Energy Tracking System.

Decision Option 2: The Commission authorizes utilities to propose alternative methods to demonstrate compliance with the Carbon-Free Standard.

All components of **Decision Option 1** have broad support amongst commenters. The Commission may choose to adopt **Decision Option 2** in addition to **Decision Option 1**; doing so would provide obligated utilities flexibility in substantiating compliance. **Decision Option 2** is contested.

B. Partially Carbon-Free Facilities

The CFS allows partial credit for partially carbon-free facilities; this provision is unique to the CFS and so has not been implemented prior to now. The determination of how *much* credit to assign to partially carbon-free facilities is not at issue here, as this topic is being further explored in the Life-Cycle Analysis Docket. Instead, at issue is how utilities substantiate compliance claims for partially carbon-free facilities: EAC retirement, a fuel mix calculation, or some other means.

CEOs, CMPAS, the Department, and Xcel weighed in on this issue.

1. Commenter Positions

The Department noted that there are instances where there is a disconnect between the percentage of generation that can be applied towards CFS and the percentage that can be applied towards EETS/RES.[96] The Department specifically noted two examples of this:

- A biomass facility—whose generation counts in full towards EETS/RES but only partially towards CFS—might have 100% of generation count towards EETS/RES, but

[95] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Minnesota Large Industrial Group Initial Comments at 2-3 (January 29, 2025) (hereinafter "MLIG Initial").

[96] Department Reply at 6.

only (for example) 50% towards CFS.[97]

- A natural gas facility with carbon capture and sequestration: this generation counts as 0% towards EETS/RES but could count at (for example) 95% towards the CFS.[98]

To count EACs for these facilities, Department recommended the Commission require:

A. EACs be issued equivalent to metered generation on a per MWh basis;
B. A single REC be issued for all generation that may be retired to demonstrate both EETS and CFS compliance;
C. A carbon-free allocator, which defines the percentage of CFS eligible generation, must be used for any generation facility that is partially CFS compliant;
D. For all generation made in a CFS partial compliant facility that is also eligible for the EETS, metered generation in A. shall be:
    A. Multiplied by C to determine the whole number of RECs to issue that are fully eligible for both the EETS and the CFS;
    B. Multiplied by one minus C to determine the whole number of RECs to issue that are only eligible for the EETS;
E. For all generation made in a CFS partial compliant facility that is not eligible for the EETS, metered generation in A. shall be multiplied by C to determine the whole number of AECs to issue that are only eligible for the CFS; and
F. The methodology to determine the carbon-free allocation shall be decided in E-999/CI-24-352.[99]
(Decision Option 3)

The Department examined other potential options to address a facility's EETS/CFS mismatch when it comes time for the utility to report compliance. These potential options included modifying biomass eligibility, establishing separate CFS credits, only issuing RECs for the CFS-eligible component of the facility, and two options that would use a carbon-free allocator (CFA).

In the first CFA option contemplated by the Department, the facility would amass EACs based on its generation, then the allocator would be applied to each EAC, creating partial EACs. This option appears to align with CEOs' recommendation that partially carbon-free facilities should

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[97] Note 50% is for illustrative purposes only; the Commission has determined that biomass may be partially compliant with the CFS on a life-cycle basis, but the credit given to biomass facilities for this partial compliance has yet to be determined in the Life-Cycle Analysis Docket.

[98] Note 95% is for illustrative purposes only.

[99] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Department of Commerce, Division of Energy Resources Late-Filed Supplemental Comments at Attachment A, pages 2-3 (May 23, 2025) (hereinafter "Department Late-Filed Supplemental").

be granted partial certificates or carbon-free credits;[100] however, CEOs supported the Commission working with M-RETS to determine a workable credit solution.[101] **(Decision Option 4)**

The Department did not recommend the CFA option that involved partial credits. In the Department's preferred CFA option, the allocator would be applied to the total MWh of generation at the time of credit generation, then the CFA would determine how many full credits are eligible for both the EETS and CFS and how many credits are only eligible for the EETS. The Department determined that this option is preferable because it (1) retains the existing 1 MWh equals 1 REC/EAC framework, (2) does not add the CFA to the credit, and (3) it would issue whole credits instead of credits that represent fractional generation for the CFS.[102] The Department also noted that this methodology has been adopted in Iowa, and so is not without precedent.[103]

CMPAS and Xcel recommended that all matters concerning partially carbon-free facilities be discussed in the Life-Cycle Analysis Docket (Docket No. E-999/CI-24-352).[104] **(Decision Option 5)**

The Department also recommended that all decisions made regarding criteria and standards to measure a utility's partial compliance with the CFS be made in the Life-Cycle Analysis Docket. Staff requested clarification on this recommendation, since it appears conflict with the Department's recommended **Decision Option 3**. In response to Staff, the Department noted that **Decision Option 3** concerns the "actual nuts and bolts of how we tally up RECs."[105]

2. Staff Analysis

Commission Staff understands the Department's distinction to mean that questions concerning facility carbon-free eligibility as a percentage of generation, determined by a life-cycle assessment of the facility, will be discussed by the Commission in the LCA Docket. The Department's proposal here instead contemplates how utilities with such facilities will substantiate compliance, regardless of how much carbon-free energy those facilities may claim. In other words, the Commission's determinations on partially carbon-free facilities in the LCA

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[100] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Clean Energy Organizations Supplemental Comments at 13 (April 16, 2025) (hereinafter "CEOs Supplemental").

[101] CEOs Reply at 7-8.

[102] Department Reply at 8.

[103] Department Reply at 8.

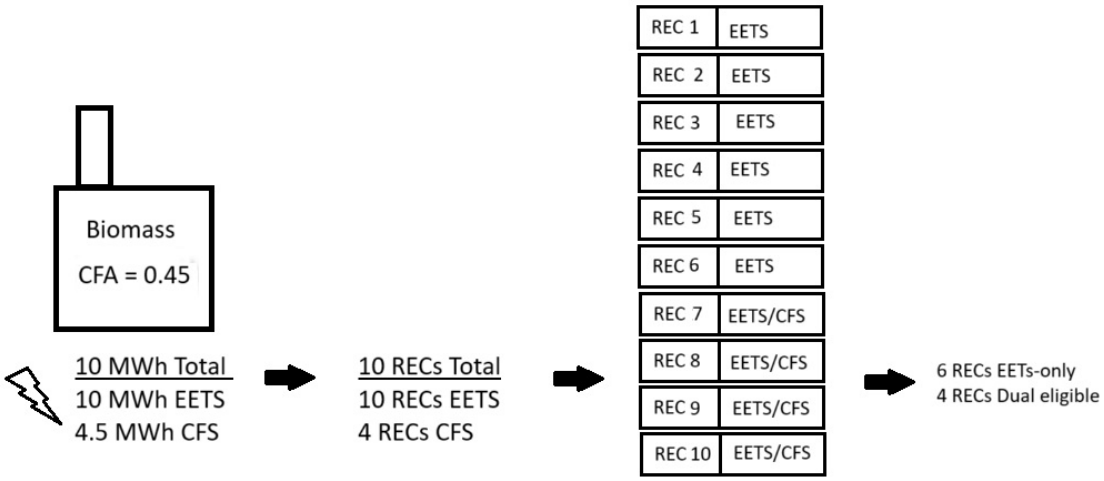
[104] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Central Minnesota Power Agency/Services at 13 (March 19, 2025) (hereinafter "CMPAS Reply").

[105] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Public Utilities Commission Permitted Ex Parte Communications Filing at 2 (May 21, 2025).

Docket will not impact the proposal here, and vice versa. Staff understands and agrees with this distinction.

Staff has put together the following graphic demonstrating its understanding of the Department's proposal; note that the biomass CFA of 0.45 is for illustrative purposes only, since the actual value for any partially carbon-free facility would be determined using a methodology selected in the LCA Docket. Staff used a CFA figure of 0.45 to demonstrate how the Department's recommendation to *only issue full RECs* appears to necessitate *rounding down* to the nearest whole REC.

Figure 1: Staff's Understanding of Applying the Department's Recommended Carbon-Free Allocator to a Partially Carbon-Free Facility



Staff is generally supportive of **Decision Option 3** and notes that this is administratively feasible with EETS/CFS compliance reporting. However, Staff also notes that this was introduced in Supplemental Comments, and no other commenters have weighed in on this proposal. Staff notes that CEOs appeared to be open to other means of tracking partially carbon-free facilities, but their current recommendation **(Decision Option 4)** is at odds with the Department's.[106] Xcel and CMPAS's recommendations to consider *all* partially carbon-free facility questions in the LCA Docket **(Decision Option 5)** are also at odds with the Department's. Staff intends to reach out to parties ahead of the Agenda Meeting and request they clarify their support or opposition to the decision options contained in these Briefing Papers. However, during the Agenda Meeting, the Commission may want to ask any clarifying questions or hear any proposed amendments or concerns about the Department's proposal.

[106] CEOs Reply at 8.

C. Net Market Purchases: Credits vs. Energy-Based Substantiation

The CFS permits partial compliance credit for carbon-free net market purchases. Like partially carbon-free facilities, this provision is unique to the CFS and so has not been implemented prior to now.

How utilities substantiate CFS claims for unspecified net market purchases is contested: some commenters argue that carbon-free net market purchases should be accompanied by EACs while other commenters argue that reporting net MWh purchases is sufficient. The conflict here is very similar as that discussed in Discussion Section VI.A. above, but specific to net market purchases. Specifically which resources count as carbon-free is not at issue here; this topic is being discussed further in the LCA Docket (Docket No. E-999/CI-24-352).

1. Commenter Positions

a. Credit-Based Compliance

CRS,[107] CSG,[108] the Department,[109] and M-RETS[110] argued that allowing net market purchase claims to be substantiated by carbon-free MWh reporting would result in the double-counting and/or double-claiming of EACs.[111] This is because the rest of CFS compliance would involve retiring credits (also called "claims-based" compliance"), while the net market purchases component would involve the reporting of net MWh purchases.

CRS elaborated on its double-claiming concerns that would arise if credits are not used when applying an annual average fuel mix:[112]

1. Using a systemwide annual average fuel mix for partial CFS compliance without requiring the retirement of RECs or equivalent EACs disconnects carbon-free attributes from actual electricity generation, creating a free-rider problem that discourages over-compliance and leads to inaccurate reporting of Minnesota's true carbon-free energy consumption.
2. This approach would send misleading market signals and would undermine regulatory oversight by allowing utilities that procure little or no carbon-free electricity to appear compliant, thereby obscuring which utilities are truly meeting or falling short of their CFS obligations.
3. Double claiming would occur as utilities would be allowed to claim carbon-free attributes that have already been purchased and exclusively owned by voluntary REC

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107 CRS Initial at 5.

108 CSG Initial at 8.

109 Department Reply at 19-20.

110 M-RETS Initial at 3.

111 Department Initial at 23.

112 CRS Initial at 5-8.

buyers, which would distort Minnesota's reported fuel mix and would artificially reduce compliance obligations.

4. By not accounting for voluntary REC purchases, utilities would be allowed to resell attributes they have already claimed for compliance, undermining core market-based accounting principles and eroding the environmental integrity and purpose of voluntary carbon-free procurement.

To mitigate the potential for double-counting and double-claiming, CRS,[113] CSG,[114] the Department,[115] and M-RETS[116] argued that the carbon-free portion of net market purchases used to substantiate CFS claims must be accompanied by REC, AEC, or equivalent EAC retirements. **(Decision Option 6)** For example, if the utility determined it had 100 MWh of carbon-free net market purchases in a year, then it would need to procure 100 EACs alongside those purchases. These commenters argued that this is the only way to avoid double-counting and double-claiming of carbon-free attributes.[117] The Department also noted that a utility using an average fuel mix calculation would inadvertently be claiming a fraction of its own carbon-free generation, and that this would be resolved by adopting the recommended decision option.[118]

b. Energy-Based Compliance

Connexus Energy (Connexus),[119] Great River Energy,[120] LIUNA,[121] and Missouri River Energy Services (MRES)[122] opposed the recommendation for REC, AEC, or equivalent EAC retirement to be required to validate net market purchases. These commenters argued that such a requirement would run counter to Minn. Stat. § 216B.1691, subd. 2d(b), which requires the Commission to allow electric utilities to receive partial compliance with the CFS for the percentage of the electric utility's annual net purchases from the regional transmission

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[113] CRS Initial at 5.

[114] CSG Initial at 8.

[115] Department Reply at 19-20.

[116] M-RETS Initial at 4.

[117] CSG noted that double-counting and double-claiming may still occur across different tracking systems.

[118] Department Initial at 24.

[119] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Connexus Energy Reply Comments at 3 (March 19, 2025) (hereinafter "Connexus Reply").

[120] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Great River Energy Reply Comments at 8 (March 19, 2025) (hereinafter "Great River Energy Reply").

[121] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Laborers' International Union of North America—Minnesota and North Dakota Supplemental Comments at 1 (April 16, 2025) (hereinafter "LIUNA Supplemental").

[122] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Missouri River Energy Services Reply Comments at 4 (March 19, 2025) (hereinafter "MRES Reply").

organization (RTO) that are determined to be carbon-free. They assert that this statutory requirement does not consider the need for electric utilities to separately purchase and retire EACs corresponding to net carbon-free market purchases from the RTO, or as a condition to receive partial compliance credit. Connexus argued that requiring utilities to purchase EACs to substantiate net market purchases would effectively disallow net market purchases from counting towards partial compliance, noting that if the legislature intended for EACs to be retired for the carbon-free portion of net market purchases, there would have been no reason for this separate section of statute.[123] LIUNA similarly characterized the recommendation as one which excludes net market sales from a utility's carbon-free energy portfolio entirely, and noted that the net market sales provision is a feature, not a bug, of the CFS statute, and one which facilitates cost-effective compliance.[124] Great River Energy argued that adopting the proposal would require EAC purchases for *all* market purchases, not just for those that are carbon-free.[125] For these reasons, Connexus, Great River Energy, LIUNA, and MRES argued that for CFS compliance substantiation, an obligated utility only needs to provide the carbon-free portion of its net market energy purchases for a given year, reported in MWh. **(Decision Option 7)**

c. Quantification Guidelines

The Department also noted that it may not always be necessary for utilities to demonstrate compliance from net market purchases.[126] To this point, the Department recommended that net market purchases should only be quantified for CFS compliance when the carbon-free share of the systemwide annual fuel mix or an applicable subregional fuel mix is necessary to demonstrate CFS compliance. **(Decision Option 8)**

No other parties commented upon this recommendation.

d. Contracts with both RECs and Unspecified Net Market Purchases

CMPAS expressed concern about how to determine CFS compliance with regards to a specific type of long-term contract that provides both fixed quantities of unspecified market energy and RECs.[127] In this type of instance, CMPAS would prefer to use the RECs directly in compliance, rather than using a partial compliance calculation for net market purchases.[128]

CSG commented upon this discussion noting that CMPAS's concern validates the need for claims-based substantiation;[129] CMPAS responded that CSG has misunderstood that its

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123 Connexus Reply at 3.

124 LIUNA Supplemental at 1.

125 Great River Energy Reply at 8.

126 Department Initial at 23.

127 CMPAS Initial at 4, Table 1, Row 3.

128 CMPAS Initial at 7.

129 CSG Reply at 10-11.

position was about existing rather than future net market purchase contracts.[130]

e. Further definition/calculation discussions and interaction with LCA Docket

Minnesota Power provided a two-step net market purchase calculation proposal that was not analyzed by other commenters.[131] Specifically, Minnesota Power recommended:

> Net market purchases should be purchases made to serve retail customers after accounting for all other carbon free energy produced, procured or generated by the company and non-carbon free energy produced, procured or generated by the company. The utility should be allowed to apply the excess RECs generated by its owned assets or purchased toward the non-carbon free portion of its market purchases or generation. Excess carbon free energy that is sold into the MISO market should be netted from the carbon-based energy used to serve customers in a two step process:
>
> Step 1, The excess should be netted from the carbon-based generation serving customers.
>
> Step 2, The remaining excess carbon free MISO market energy sales from Step 1 should be netted from MISO market energy purchases. The remaining market purchases after Step 1 and Step 2 are the market purchases to which the MISO market carbon free percentage is applied.[132]

While no commenters addressed Minnesota Power's proposal, multiple commenters correctly noted that Staff has requested comment on net market purchases in both this docket and the LCA Docket (Docket No. E-999/CI-24-352). To address this overlap, CMPAS requested that if the Commission provides a definition of net market purchases in in the LCA Docket that an additional notice of comment period be opened in the present CFS Docket to comment on how net market purchases may count towards CFS compliance.[133] **(Decision Option 9)** Alternatively, CMPAS supported the Department's recommendation to defer all net market purchase decisions to the LCA docket.[134] **(Decision Option 10)**

2. Staff Analysis

Staff believes further record development is needed concerning Minnesota Power's proposed

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130 CMPAS Supplemental at 3.

131 Minnesota Power Initial at 4-5.

132 Id. at 4-5.

133 CMPAS Reply at 13.

134 Department Late-Filed Supplemental Attachment A at 3.

net market purchase calculation, but notes that the LCA Docket may or may not be the appropriate place to do so. Staff is therefore supportive of CMPAS's proposal for a final round of comments on net market purchases, or any other unresolved matters, in the CFS Docket, after final determinations have been made in the LCA Docket. **(Decision Option 9)**

As noted in the Background Section above, in its November 7, 2024 Order the Commission determined that further record development was needed concerning the calculation and definition of net market purchases, both in the CFS Docket and in the newly created LCA Docket. Pending the outcome of these investigations, the Commission provisionally directed utilities, in their filings under the CFS and in resource plans under Minn. Stat. 216B.2422, to do the following:

- Calculate the percentage of carbon-free market purchases using an applicable regional transmission organization subregion—using annual energy fuel mix data—as practicable.[135]
- Calculate the percentage of carbon-free energy, when a utility purchases energy from a specified resource such as in the context of a bilateral contract or power purchase agreement, based on the percentage of carbon-free energy generated by that resource.

Staff notes that while the Commission's provisional decisions contemplate an annual energy fuel mix calculation, neither decision precludes a credit-based or an energy-based compliance reporting method. Such a calculation can be paired with both credit claims and energy claims.

The record clearly displays how using an energy-based market fuel mix calculation to substantiate carbon-free claims would result in double claiming of environmental attributes. This was undisputed. Instead, those in favor of using energy-based compliance for net market purchases argued that such substantiation is allowed under the REO statute.

It is also clear to Staff that the statute permits partial compliance through the carbon-free portion of net market purchases, and that requiring net market purchases to be accompanied by a separate purchase of RECs, AECs, or equivalent EACs might render the net market purchases provision meaningless.

Ultimately, the Commission has broad authority in how it requires utilities to substantiate carbon-free net market purchase compliance claims.

Staff notes that in the case of CMPAS, a utility might prefer to use EACs instead of MWh to substantiate its net market purchase claims. To account for this, Staff has used the term "may" in **Decision Option 7**.

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[135] Staff reiterates that as this directive is worded, utilities participating in MISO will calculate net market purchases using MISO North data, whereas utilities participating in SPP will use systemwide data. This has to do with what data sources are currently available. For a further discussion of this, see Staff September 12th Briefing Papers at 75-77.

Staff notes that currently, all REO Standard compliance is substantiated through credit retirements. Should the Commission deviate from its credit-based approach and allow energy-based claims, the record will need to be further developed as to exactly how utilities' net market purchases will interact with credit retirements to verify compliance. Staff notes that merging these two types of compliance should be administratively feasible, but the present record does not include suggestions on how to accomplish this task.

The Department also recommended that net market purchases only be quantified for CFS compliance when the carbon-free share of the systemwide annual fuel mix or an applicable subregional fuel mix is necessary to demonstrate CFS compliance, **Decision Option 8.** Staff is not clear on the rationale behind this recommendation, and no other parties commented on it, so Staff recommends the Commission ask the Department and other parties for any clarifications, amendments, or concerns about this decision option.

Finally, Staff notes that the Department recommended deferring all net market purchase decisions to the LCA Docket **(Decision Option 10)** while simultaneously recommending credit-based compliance **(Decision Option 6)** and quantification guidelines **(Decision Option 8)**. Staff speculates that this might be a similar situation as with the Department's recommendation with partially carbon-free facilities and the Department's current recommendations are about the "actual nuts and bolts of how we tally RECs." Staff intends to solicit commenter positions on decision options, but notes that the Commission may wish to clarify the Department's position in the Agenda Meeting.

D. Reporting: Annual REO Reports

Broadly, the REO Statute requires biennial reporting, whereas the Commission has added additional requirements for utilities to file annually and in the pre-compliance period (which occurs prior to 2030, in the case of the CFS). Parties recommended a number of different options concerning these reports. Since the Commission has developed fairly standardized reporting practices with the implementation of the RES (now EETS), SES, then DSES, Staff offers Decision Options that reflect prior Commission Orders.

1. Commenter Positions

a. Maintaining the existing structure:

The Department stated its preference to retain the existing REC reporting structure to the greatest extent practicable, while modifying the structure to allow for newly proposed reporting requirements. At this point in time, the Department stated there was no need to order any additional requirements to determine whether an electric utility was in compliance with the CFS as the existing reporting structure would be sufficient.[136]

[136] Department Initial at 16-17.

b. Cadence and Timing:

CMPAS,[137] Connexus,[138] the Department,[139] GRE,[140] Minnkota,[141] MP,[142] and Xcel[143] recommended that CFS preparedness reporting should occur via Integrated Resource Plan (IRP) for IRP-filing utilities, and that for utilities not subject to IRPs, reporting should happen at the time of a utility's EETS reporting. CEOs noted that the statute requires filings to be made every two years, while in practice IRPs may be filed at longer intervals. CEOs instead recommended that the Commission require all utilities subject to the CFS to file their preparedness reports at least every two years, and that all CFS reporting be done in a single docket.[144] CSG further recommended that each obligated utility propose its own interim targets for 2028 and onwards, to be approved by the Commission.[145] Xcel disagreed with CSG's position, noting that the statute specifically lays out goals for 2030, 2035, and 2040.[146] The Department recommended that utilities begin compliance reporting in 2029 for generation year 2028.[147]

c. Forms

CMPAS suggested preparedness reporting this could occur through an additional question on the report forms currently used by utilities to demonstrate EETS compliance,[148] while Connexus recommended a dedicated worksheet added to the EETS template.[149] CEOs recommended—and Xcel agreed—that the Commission ask the Department to propose an update of the reporting template, and that the Department should consult with utilities in preparing this update and other stakeholders should be able to comment upon it once proposed.[150] The Department asserted that no stakeholder input was needed in the development of a reporting template.[151]

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137 CMPAS Initial at 3.

138 Connexus Initial at 2.

139 Department Initial at 3-4.

140 Great River Energy Initial at 1.

141 Minnkota Initial at 1.

142 Minnesota Power Initial at 2.

143 Xcel Initial at 1.

144 *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Clean Energy Organizations' Initial Comments at 18 (January 29, 2025) (hereinafter "CEOs Initial").

145 CSG Reply at 4.

146 *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Northern States Power Company d/b/a Xcel Energy Supplemental Comments at 5 (April 16, 2025) (hereinafter "Xcel Supplemental").

147 Department Late-Filed Supplemental Attachment A at 1.

148 CMPAS Initial at 3.

149 Connexus Initial at 2.

150 CEOs Supplemental at 13, Xcel Supplemental at 5.

151 Department Reply at 13.

d. Formula

To evaluate preparedness, Xcel recommended the Commission use the same formula that Xcel used in its most recent IRP.[152]

e. Dual Purpose RECs

CMPAS proposed that if any RECs used for CFS compliance were also retired and documented for EETS compliance during the same period, that a standardized CFS compliance form, report, or other mechanism be established that can simply reference the REC retirements already made.[153] Minnesota Power suggested that the best way to demonstrate dual use of RECs is through a workbook submitted to the Commission as a compliance filing.[154]

f. True-Up Period

The Department recommended that the Commission order a 2030 to 2034 CFS compliance true-up period of three months after the conclusion of the reporting year.[155] Separately, and in regard to net purchases, the Department recognized that utilities may not know their final market position or fuel mix until after the reporting year, and so supported allowing EAC purchases in the first three months of the following generation year to close any compliance gaps.[156] Xcel responded that a three-month would be more restrictive than current practice, as utilities have until May 1st each year to transfer a sufficient number of RECs to their M-RETS retirement sub-accounts to meet the standards for the prior calendar year.[157] The three-month recommendation would also have the effect of limiting the EETS "true-up" period.

g. Further reporting requirements

- CEOs recommended additional reporting requirements. CEOs' reporting recommendations related to attributing carbon-free generation to Minnesota and are discussed in Discussion Section VII.G. below, "Geographical Considerations." CEOs' reporting recommendations concerning hourly data reporting are discussed in Discussion Section VII.D. below, "Hourly Data Reporting."
- The Department recommended additional reporting requirements. The Department's reporting recommendations related to REC/AEC procurement reporting are discussed in Discussion Section VII.G. below, "Geographical Considerations." The Department's recommendations concerning hourly data reporting are discussed in Discussion Section VII.D. below, "Hourly Data Reporting."
- CEOs, CMPAS, and the Department commented on the possibility of the Department

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152 Xcel Initial at 3.

153 CMPAS Initial at 6.

154 Minnesota Power Initial at 4.

155 Department Reply at 9.

156 Department Late-Filed Supplemental Attachment A at 3.

157 Xcel Supplemental at 4.

performing enhanced audits of REO reports. These recommendations are discussed in Discussion Section VII.K. below, "Enhanced Auditing."

- Minnesota Large Industrial Group (MLIG) made a series of reporting recommendations that could feasibly be included in annual REO reports. Staff considers these comments important and would like further record development on them in CFS Round 4 Comments. Staff has grouped these comments into Discussion Section VIII.B. below, "Cost and Reliability Reporting."

2. Staff Analysis

Staff believes there is confusion surrounding the discussion of preparedness reporting and standards and criteria to measure CFS compliance.

The term "preparedness" was used by Staff to recognize that "compliance" has not begun and thus REC retirements are not an expected part of compliance at this time. As has occurred with the SES and DSES, it very well may be that additional information and discussion is required ahead of the first year of compliance.

Second, commenters seem to be unaware of the Commission's history with preparedness reporting for the state's renewable energy objectives. As detailed in the background section of these Briefing Papers, the Commission has required information from utilities ahead the initial year of compliance for both the SES and DSES. References to these processes and the resulting reporting requirements were absent from the present discussion.

So far as the EAC being retired was generated in an eligible year—recognizing that RECs currently have a four year shelf life for compliance—it does not matter when it is bought by a utility. REC retirements are due each year on May 1st. Utilities have until then to gather and retire the RECs they will use for compliance for the previous calendar year.

Finally, commenters may not be familiar with the form, function, and requirements of utilities' current REO reporting template. In the present docket, commenters discussed the need to integrate CFS reporting with broader REO reporting and require that utilities provide CFS compliance information on an annual basis. This has been standard practice since the SES compliance reports were merged with REO reports in 2020.

To address the multiple recommendations provided, Staff provides the following decision options, which have been structured based on the Commission's prior decisions for establishing SES and DSES reporting requirements. Staff believes that these reporting requirements address several of the recommendations made by commenters including the content, location, and type of information expected in annual CFS reports, while clarifying what information is expected only until 2030.

Staff Decision Option 11: Beginning in 2026, each electric utility shall file a report on June 1st with its Renewable Energy Objectives compliance report in Docket No. E-999/PR-YR-12 that

includes the following information detailing its efforts toward complying with Minnesota's Carbon-free Standard:

A. Annual Minnesota retail sales for the previous calendar year.
B. Annual net market purchases from the previous year.
C. Annual qualifying carbon-free generation procured or generated by the electric utility in the previous calendar year, including the total number of facilities registered in M-RETS to that utility and eligible Renewable Energy Credits (or other equivalent Energy Attribute Credits) generated in the past year from those facilities.
D. A list of facilities determined to be partially compliant with the CFS, including the name of the facility, the facility fuel type, and the percent of that facility's output determined to be carbon-free.
E. From 2026-2030, electric utilities must also report the following:
    i. Estimated amount of carbon-free generation (expressed as capacity) a utility would require to obtain in 2030.
    ii. Estimated carbon-free requirements to meet the CFS in 2030.
    iii. A short summary of ongoing efforts to obtain carbon-free energy, including a brief summary of the anticipated resource mix for CFS compliance.
    iv. Any considerations, such as those outlined in Minn. Stat. § 216B.1691, subd. 2b, that may create challenges with achieving compliance, and which under Minn. Stat. § 216B.1691, subd. 2h(f), may allow the Commission to modify or delay implementation.

AND

Staff Decision Option 12: The Commission delegates authority to the Executive Secretary to work in conjunction with the Department of Commerce and utilities to update the Renewable Energy Objectives reporting template to incorporate the reporting requirements approved in this docket and modify them as necessary based on the results of the LCA Docket, Docket No. E-999/CI-24-352.

These recommendations should be sufficient to cover the Commission's statutory obligations concerning utility reporting requirements. However, should the Commission choose to incorporate any of the "Further Reporting Requirements" recommended by CEOs and the Department (discussed in Discussion Section VI.D.1.g. above), the Commission may simply add those additions onto **Staff Decision Option 11.**

Further, the Commission may wish to re-visit these reporting requirements in 2030, before utilities provide their first compliance report in 2031 (utilities report on compliance from the previous year). The Commission could commit to take this action now or evaluate this option again prior to 2031.

VII. Additional Considerations

Commenters brought up other issues for Commission consideration that would not be required to determine compliance under the statute. These topics include: hourly matching for CFS compliance, an hourly matching workgroup, hourly matching in IRP modeling, hourly data reporting, hourly EAC certification, re-evaluating the REC shelf life, geographical requirements and reporting, line losses, residual mix accounting in net market purchases, clean transition tariffs, enhanced auditing of REO Reports, and a request for common definitions.

A. Hourly Matching for CFS Compliance

In its Initial Comments, the Department made a series of recommendations aimed at implementing an "hourly matching" requirement for utilities demonstrating compliance with the CFS. Hourly matching refers to a method of EAC accounting in which obligated utilities would retire hourly EACs in accordance with the utility's hourly load. As defined by the Department, "If hourly EAC matching is required, then electric utilities would need to true-up generation each hour, which may require sales of EACs when generation exceeds load, and purchases of EACs when EAC generation is insufficient to match load."[158]

However, after significant pushback and analysis from other commenters in Reply Comments, the Department withdrew and/or modified its recommendations concerning hourly matching in Supplemental Comments. Currently, the Department has two standing hourly matching recommendations: one for a Commission-led hourly matching workgroup, and one requiring IRP-filing utilities to incorporate hourly matching into their modeling. The Department also has two standing hourly *reporting* recommendations, which are discussed further in Discussion Section VII.D. below.

1. Commenter Positions

The following table shows the commenters who were in favor of the Department's initial hourly matching for compliance proposal and those who were opposed to it.

[158] Department Initial at 7.

Table 2: Commenter Positions on Department's Initial Hourly Matching Recommendation

Supported	Opposed
Department Minnesota Center for Environmental Advocacy Fresh Energy Sierra Club EnergyTag Zero Lab	Great River Energy Rochester Public Utilities Connexus Energy Central Municipal Power Agency/Services Missouri River Energy Services Minnkota Power Cooperative Basic Electric Power Cooperative Minnesota Municipal Utilities Association East River Electric Minnesota Rural Electric Association Otter Tail Power Company Xcel Energy Southern Minnesota Municipal Power Agency ALLETE Minnesota Power International Union of Operating Engineers 49 and North Central States Regional Council of Carpenters LIUNA

a. Arguments in Support of Hourly Matching

Commenters in favor of hourly matching argued that hourly matching would incentivize "clean firm" power, more effectively decarbonize Minnesota's retail electric load, dis-incentivize Minnesota utilities from building carbon-intensive resources, and lead to the creation of a more efficient REC/EAC market. Commenters also say there is interest from voluntary markets who have decarbonization goals, and that voluntary matching is the future of the REC/EAC accounting.

Supporters argue that an hourly matching requirement would dis-incentivize Minnesota utilities from building carbon-intensive resources. The Department highlighted that while the CFS requires utilities to build or procure enough carbon-free energy to meet its Minnesota load, "[n]othing in the CFS precludes a utility from maintaining or building additional CFS-ineligible generation."[159] It's possible that a utility will build generation in excess of its Minnesota load obligation in order to meet MISO capacity requirements; however, MISO's dispatch protocols may lead to CFS-ineligible generation being chosen instead of CFS-eligible generation.[160] As a result, while the utility may theoretically be able to generate enough carbon-free energy to

[159] Department Initial at 6.

[160] For example, future hydrogen combustion turbines might be 100% carbon-free but dispatched last because it is a high variable-cost resource, which tends to be penalized under MISO dispatch. Department Initial at 6.

cover its Minnesota load, in practice this may not happen. The Department notes that in shortfall instances, "an electric utility may need to purchase energy attribute certificates to fill in the generation gap between carbon-free generation and load."[161]

Zero Lab provided a study in which in concluded:

> Our results also suggest that intermediate matching targets which drive toward the long-run goal of 100% matching are necessary to minimize costs and maximize impact. A "Flexible" hourly matching requirement that allows utilities to pick and choose the hours they match is incredibly easy to comply with in a wind-rich state like Minnesota, and can also create path dependencies where the resource investments made in the 2030s are not necessarily consistent with a long-run goal of 100% hourly matching. By contrast, a "firm" hourly matching requirement aligns near-term investments better with long-run goals, drives impact even in early years, and creates an earlier demand-pull for advanced technologies like long-duration energy storage. Additionally, because complete hourly matching with deliverable clean power will eventually be necessary to truly eliminate Minnesota's reliance on climate-warming sources of power, a policy that intentionally drives toward this goal from the start is likely the best way to deliver on the state's promise to use 100% carbon-free electricity[162]

b. Arguments Against Hourly Matching

Commenters against hourly matching argued that the Commission may not have the authority to order hourly matching as a means by which utilities comply with the CFS. Second, some commenters argued that hourly matching would be costly, with the potential for diminishing emissions reduction returns as costs increase. Third, commenters argued that there are numerous logistical concerns, including: no current market for hourly RECs and EACs, impacts on pursuit of PPAs, and complications for utilities participating in both MISO and SPP. Fourth, two commenters argued that hourly matching may not always lead to reduced emissions.

i. Statutory Authority

In Reply Comments, the Aligned Utilities and others challenged the statutory authority for the Commission to require hourly matching as a means for compliance. The Aligned Utilities noted that the compliance language of the EETS (formerly RES) is identical to the CFS and given the

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[161] Department Initial at 6.

[162] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Zero Lab Supplemental Comments at 7 (April 16, 2025) (hereinafter "Zero Lab Supplemental").

fact that the EETS/RES had been in place since 2007, there was no reason to believe the Legislature intended to significantly change how compliance was intended to function. The Commenters argued that the Legislature could have deliberately indicated that it intended the Commission to implement some form of hourly matching but chose not to. The Aligned Utilities reminded the Commission that the Minnesota Supreme Court requires that a statute be read as a whole, with effect given to all of its provisions and that the Commission was only tasked with the issuance of necessary orders. Finally, the Aligned Utilities explained that hourly matching would treat EACs differently, contrary to the directive of the statute. The Department addressed each of these legal concerns, but ultimately disagreed with the conclusions of the commenters, maintaining that the Commission has the statutory authority.[163]

ii. Cost Issues

Multiple commenters argued that requiring hourly matching would be costly. The Aligned Utilities cited the likelihood of high demand during systematic shortages of EAC generation, the additional competition for these same EACs from voluntary markets, and the immaturity of EAC trading markets not having sufficient liquidity to plan for high-demand hours.[164] CMPAS cited the high administrative cost of hourly matching, particularly for small utilities and ones that do not file IRPs. Both CMPAS and Xcel cited marginal transmission planning cost concerns.

Great River Energy retained experts to review and independently assess evidence related to clean energy compliance standards, including the Department's proposed hourly matching standard. They found that private hourly matching is more expensive than annual matching on both an absolute basis and a $/MWh basis. After conducting an indicative cost estimate, in the Minnesota context, they found that the potential cost of hourly matching with renewable would be $43-260/MWh more than annual matching, depending on scenario assumptions such as the availability and cost of an hourly market for RECs.[165]

Xcel provided EnCompass results in which it incorporated hourly matching. Xcel's initial modeling suggests that it would need to add 17,700 MWs of storage (over 100 times the storage currently operational in all of MISO) and over 4,000 MW of additional solar resources by 2040.[166] This would result in a 60 percent increased revenue requirement to serve the same customer load, which would increase rates by approximately $45 per month.[167]

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[163] See Department framing of legal arguments, *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Department of Commerce, Division of Energy Resources Supplemental Comments at 9-11 (April 16, 2025) (hereinafter "Department Supplemental").

[164] See Department framing of cost arguments, Department Supplemental at 22-23.

[165] Great River Energy Reply Appendix 1 at 3 and 23.

[166] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Northern States Power Company d/b/a Xcel Energy Reply Comments at 9 (March 19, 2025) (hereinafter "Xcel Reply").

[167] Xcel Reply at 2.

iii. Logistical Issues

In Reply Comments, some commenters expressed logistical concerns with hourly matching. CMPAS' concerns included potential invalidation of contracts, new problems with carbon accounting, discouragement of utilities pursuing PPAs, lack of means to induce energy storage in PPAs, problems with contractual replacement energy. MRES' concerns included that IRP software does not support hourly matching; Basin noted that it is problematic because it participates in both MISO and SPP.[168]

iv. Environmental Issues

Some commenters expressed concern that hourly matching may lead to increased emissions. CMPAS cited a study claiming that hourly matching is less effective at reducing emissions than optimizing battery dispatch at the grid level. The Department refuted CMPAS's comments, claiming that CMPAS misrepresented the findings of the study.[169] The Brattle Group, who conducted a study for Great River Energy in Reply Comments, brought up concerns about instances in which the marginal unit, storage efficiency losses, and transmission constraints may lead to increased emissions. The Department acknowledged aspects of the Brattle Group's study to be accurate, but argued that no evidence was actually put forward to demonstrate that hourly matching will increase emissions.[170] EnergyTag criticized the Brattle Group's study, stating that it was flawed with cherry-picked conclusions.[171]

2. Staff Analysis

Staff agrees that hourly matching may very well be necessary to achieve truly 24/7 emission-free electricity. However, legal considerations aside, Staff also agrees that the Department's proposal was premature, given the numerous cost, logistical, and environmental considerations outlined by commenters. As this is an emerging issue that has garnered interest in voluntary markets, the Commission may wish to wait and learn more of best practices and potential pitfalls from these voluntary markets, or until it receives an explicate directive from the legislature to implement such a compliance mechanism.

In Supplemental Comments,[172] Department withdrew its recommendations supporting hourly matching to demonstrate CFS compliance, and so the Commission does not need to make a determination on this matter.

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[168] See Department framing of logistical concerns, Department Supplemental at 13-16.

[169] Department Supplemental at 20-21.

[170] Department Supplemental at 21-22.

[171] EnergyTag Supplemental at 4-6.

[172] The Department's final list of recommendations was clarified in Late-Filed Supplemental Comments.

B. Hourly Matching Workgroup

1. Commenter Positions

Although the Department withdrew its recommendation for hourly matching to substantiate CFS compliance, the Department recommended the Commission order the creation of a Commission-led hourly matching stakeholder workgroup. This workgroup would be tasked with the analysis, development, testing, and recommendation of best practices for the optimization of societal costs as they pertain to:

A. Hourly matching for CFS compliance;
B. Methodologies to implement hourly matching scenario requirements in integrated resource plans;
C. The integration of transmission constraints in integrated resource plans;
D. The integration of energy attribute certificates and allocation thereof in integrated resource plans;
E. Stochastic modeling of variable renewable generation into integrated resource plans; and
F. The co-optimization of transmission and generation resources.

(Decision Option 13)

Since the Department presented its Commission-led workgroup recommendation in Supplemental Comments, no commenters have weighed in on the Department's hourly matching workgroup recommendation. Staff intends to have parties clarify their positions ahead of the Agenda Meeting, but Staff recommends the Commission discuss any commenter clarifications, amendments, or concerns on **Decision Option 13** during the Agenda Meeting.

2. Staff Analysis

In this instance, Commission Staff does not recommend the establishment of a Commission-led workgroup. Staff believes it would only be appropriate to convene such a workgroup if the Commission clearly possesses the authority to require hourly matching and if hourly matching has sufficiently developed. Given the unresolved legal questions surrounding the use of hourly matching as a means of CFS compliance, Staff views the Commission's authority to mandate any form of hourly matching as a result of this workgroup as uncertain.

Further, workgroups have historically been successful when commenters agree that discussing the technical details of implementation would be more productive than continuing with multiple rounds of comment. In this instance, more than half of those participating in the workgroup would be opposed to the idea of hourly matching outright, while also believing that the Commission has no authority to act on the issue being discussed in the workgroup. Because of this, Staff questions whether this workgroup would ultimately be productive or yield results worthy of the time required to convene the workgroup. Staff understands that this topic is of interest to the Department, but the Department does not require a Commission-led workgroup

to continue to explore this topic.

C. Hourly Matching in IRP Modeling

1. Commenter Positions

The Department continued to recommend the Commission order all integrated resource plans where the utility uses a capacity expansion model to incorporate hourly matching constraints in the models to demonstrate CFS compliance. **(Decision Option 14)**

The CEOs supported the Department's recommendation, noting that it would ensure that utilities acquire the resources that best fit their hourly demand. Further, the CEOs claimed that hourly matching would provide the Commission and stakeholders with the information they need to determine the extent to which the plan minimizes environmental harms, limits risks posed by changing factors beyond the utility's control, reduce long-term regulatory risks, and achieve the state's greenhouse gas reduction goals.[173]

EnergyTag and Google, LLC (Google) also supported the inclusion of hourly matching analysis in future integrated resource plans.[174] Google explained that ambitious hourly matching targets support the development of cost-effective clean energy portfolios, and that high targets can position Minnesota as a clean electricity exporter, with excess energy displacing generation in neighboring grids.[175] According to Google, over 90% hourly matching is achievable with existing clean technologies and storage.

MRES and Great River Energy opposed the Department's recommendation for utilities to use hourly matching in resource planning models. MRES argued that its resource planning software is not capable of modeling hourly RECs and it is unaware of other resource planning software capable of doing so.[176] Great River Energy's concern is that requiring hourly matching in IRP modeling is unduly burdensome, fraught with uncertainty, and the benefits are unclear. Great River Energy noted the following specifics:

- EnCompass, the capacity expansion modeling software used by Great River Energy, has limitations as to what it can do. Great River Energy recommended that before an hourly matching modeling requirement is ordered, modeling stakeholders should meet with the EnCompass software developers to discuss "the capabilities, limitations, and value added" that could come from incorporating hourly matching into the model.[177]
- It would be difficult for Great River Energy to develop an 8760 (number of hours in a

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[173] CEOs Reply at 3.

[174] EnergyTag Supplemental at 12.

[175] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Google, LLC Reply Comments at 1 (March 19, 2025) (hereinafter "Google Reply").

[176] MRES Reply at 2.

[177] Great River Energy Reply at 10-12.

year) REC/AEC price forecast over a 15-year period because there is no current market for hourly RECs/AECs. Great River Energy argues that the uncertainty here would make the results of the model unreliable.

- Great River Energy says the Commission already takes into account the future cost of carbon through externality/regulatory costs. In other words, there is already an hourly carbon price signal built into the modeling, which means that there is an implicit hourly penalty to building/operating a carbon-intensive resource already.

Great River Energy also noted that the Department contended that modeling hourly matching will alleviate concerns about utilities being "overly dependent"[178] on REC/AEC markets; Great River Energy argued that there not only is no guidance on what may qualify as "overly dependent" but also that the statute places no limits on the number of credits a utility may purchase for compliance.[179]

The Aligned Utilities also noted since hourly REC/AEC markets do not exist, and no other state requires hourly demonstrations, utilities would not be able to reflect hourly matching in their resource plan model.[180]

In Reply Comments, Xcel explained how it had modeled hourly matching to evaluate a voluntary program.[181] As noted above, its initial results showed extensive buildout of storage and solar resources in advance of 2040, accompanied by a 60 percent increase in its revenue requirement. In response to this, the Department noted that Xcel's model may have too tight of constraints:

> Xcel's model appears to be enforced at 100% compliance for all hours, which treats CFS compliance as stricter constraint than reliability. Reliability planning uses a standard, such as such as a one-in-ten year loss of load expectation (LOLE), which allows EnCompass to relax the constraint once the standard is met, if added capacity no longer provides a lowest cost option. Similar to reliability planning, the higher the reliability standard is set, the higher the system costs become to plan for an increasingly unlikely event, which is what Xcel refers to as an "overbuild of resources."[182]

The Department further noted that Xcel's model may not have incorporated the future cost of

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178 Department Initial at 12.

179 Great River Energy Reply at 11-12.

180 *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Aligned Utilities' Reply Comments at 4 (March 19, 2025) (hereinafter "Aligned Utilities Reply").

181 Xcel Reply at 6-9.

182 Department Supplemental at 33.

carbon in a way that accurately reflects resource dispatch.[183] The Department provided Late-Filed Supplemental Comments critiquing Xcel's model on a variety of additional fronts.[184] Xcel responded to the Department's Late-Filed Supplemental Comments and critiqued the Department's process.[185]

2. Staff Analysis

As an initial matter, Staff would like to clarify that all models and modeling results are necessarily flawed. The goal of modeling is not to achieve perfect foresight, but to use known and predicted information to the best of the modeler's ability, then strain the model with contingencies and find the impact on the utility's proposed plan. Part of modeling is knowing the model's limitations, explaining those limitations in comments, and improving upon processes and information when possible. In short, modeling is iterative and imperfect. As such Staff considers certain objections—such as the current lack of hourly REC/AEC pricing data rendering a model unreliable—as a legitimate but not disqualifying concern.

Requiring utilities to examine hourly matching in the context of a resource plan model may be a reasonable course of action. Many commenters expressed interest in the incremental cost of hourly matching and have questioned the emissions benefits of hourly matching; these are two attributes that could be further examined in a model. While Great River Energy pointed out that the Commission already has the future cost of carbon built into the model in the form of regulatory/externality costs, Staff notes that regulatory costs and CFS constraints (whether annual or hourly) serve different functions: essentially, the first is a carbon tax and the other is a carbon cap. Examining each function on its own could help modelers and parties understand the least-cost path towards achieving Minnesota's carbon-free goals.

However, the proposed requirement may also be unnecessary. Staff notes that some commenters appear to be more concerned with precisely how often carbon-intensive resources are being dispatched in a utility's model; this is something already examined by modelers and could simply be incorporated into resource planning as an additional reporting requirement. To this end, Staff offers the following Decision Option:

Staff Decision Option 15: In future resource plans, IRP-filing utilities should report hourly information concerning carbon-free versus non-carbon-free resources for each of the Commission's required regulatory/externality scenarios.

Should the Commission wish to require hourly matching in a model, Staff suggests some appropriate parameters and expectations be put in place. First, the Commission may wish to determine that only utilities with an hourly-matching-capable capacity expansion modeling

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[183] Department Supplemental at 34.

[184] Department Late-Filed Supplemental at Appendix C.

[185] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Xcel Energy at 1-2 (June 5, 2025).

software (such as EnCompass) should examine hourly matching. Second, the incorporation of hourly matching into should be understood as a process that will necessarily be flawed and needs to be refined over time, with a goal of allowing modelers and parties to gain a better understanding of the costs, benefits, possibilities, and limitations of a potential future regulatory hourly matching requirement. Third, given the many uncertainties around a lack of hourly REC/AEC pricing information, the ongoing discussion about the best way to incorporate hourly matching into the model, the initial results from Xcel's model, and the existing incorporation of hourly carbon price signals (ie regulatory/externality costs), Staff would caution against requiring hourly matching in the utility's base case, or require hourly matching as a prerequisite for plan approval. Instead, Staff considers it more appropriate at this time to examine hourly matching as a modeling sensitivity/contingency. To this end, Staff offers the following Decision Option:

Staff Modified Decision Option 14: In future resource plans, and to the extent practicable, IRP-filing utilities shall incorporate one or more contingencies that use an hourly matching construct to achieve the state's CFS. Utilities should accompany this with a discussion of the potential costs, benefits, possibilities, and limitations of a potential future regulatory hourly matching requirement.

D. Hourly Data Reporting

The Department and CEOs made recommendations for utilities to report hourly data. This is distinct from, and does not require, an hourly matching construct.

1. Commenter Positions

The Department made two recommendations that support a future hourly matching construct without requiring hourly matching as a means of compliance at this time; these recommendations instead simply require utilities to report hourly data without matching RECs/AECs to load. Specifically, the Department recommended:

- The Commission order all electric utilities to report sales and purchases of EACs at the time interval required for CFS matching **(Decision Option 16)**; and
- The Commission order electric utilities to all report hourly Minnesota retail electric sales **(Decision Option 17)**.

The Department asserted that the current proceeding is fundamentally about what "carbon-free electricity" means in practice, and that the Commission must decide if carbon-free means clean, firm power that matches real-time loads when they occur; retiring renewable energy certificates (RECs) from anywhere in the country while relying on fossil fuels for physical energy and grid reliability; or somewhere in between. The Department argued that this data will help the Commission and intervenors understand the influence that CFS-ineligible generation has on a utility's ability to serve each electric utility's Minnesota load.

In Initial Comments, the CEOs also included a request for hourly data. The CEOs recommended

that electric utilities be required to include the following information when reporting on CFS compliance:

When reporting on CFS compliance, electric utilities shall include the following information:

a) the utility's projected reliance on RECs purchased without purchasing the associated energy (unbundled RECs) to comply with the CFS through 2040.
b) A discussion of the expected hourly timing of anticipated carbon-free generation (with bundled RECs) and unbundled REC purchases through 2040.
c) An estimate of what the utility's projected compliance with the CFS would be through 2040 if RECs could only be claimed if they were time-matched.
d) For filings verifying compliance with a previous year's CFS, an estimate of the utility's carbon-free percentage if the RECs it purchased and generated had to be time-matched with the utility's demand on an hourly basis.
e) a discussion of any barriers to acquiring the information listed above and efforts the utility has made to obtain or estimate it.

(Decision Option 18)

The CEOs asserted that hourly data is required to achieve the deeper levels of decarbonization contemplated in today's climate and clean energy objectives.[186] The CEOs view their recommendation as an opportunity for the Commission to understand how close Minnesota utilities are to achieving truly 100% carbon-free grid and to identify the barriers and opportunities of shifting toward time-matched RECs. Citing analysis conducted by Form Energy, Great River Energy, and the Humphrey School of Public Affairs, the CEOs reported that the current annual REC accounting approach produces substantial carbon dioxide and only meets hourly demand with carbon-free energy "40 to 70 percent of the time."[187] CEOs also cited the Biden Administration's previous goal of achieving 50% time-matched REC retirements by 2030 for purchases by the federal government.

CEOs also made legal arguments supporting hourly data requests: they stated that by requiring information on time-matching now would not only help the Commission and parties better evaluate how well utilities' IRPs "minimize adverse effects upon the environment, "[188] enhances a utility's "ability to respond to changes in the financial, social, and technological factors affecting its operations,"[189] and "limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control,"[190] but also could better prepare the Commission to respond to future laws that require hourly

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[186] CEOs Initial at 10.

[187] Form Energy, Great River Energy, and U of M Humphrey School of Public Affairs, "Form Energy White Paper," submitted as Appendix F to Great River Energy's 2023-2037 Integrated Resource Plan, In the Matter of Great River Energy's 2023-2037 Integrated Resource Plan, Docket No. ET-2/RP-22-75 (March 31, 2023), p.4.

[188] Minn. R. 7843.0500, subp. 3, item C.

[189] Minn. R. 7843.0500, subp. 3, item D.

[190] Minn. R. 7843.0500, subp. 3, item E.

matching.[191]

There was general pushback from utilities regarding hourly reporting.

Basin pointed out that Minn. Stat. § 216B.1691, subd. 3(a)(9) includes reporting on "the dates when the energy associated with the credits was generated," but does not prescribe hourly reporting.[192]

Xcel similarly opposed the CEOs' recommendations on legal grounds, arguing that the CEO recommendations overcomplicate compliance reporting and go beyond the plain language statutory requirements.[193] Xcel also noted that the CEOs recommendations are not feasible, since RECs are time-stamped by M-RETS on a monthly—not hourly or daily—basis. Xcel argues that since CEOs' recommendations rely on mechanisms that do not exist, the recommended analyses is impossible. Xcel stated that even if it were possible, the recommended reporting would be burdensome with little to no benefit.[194]

CMPAs expressed concern about the Department's recommendation, noting that this is a labor-intensive request unrelated to the statute, which contemplates annually based compliance.[195]

CMPAS also argued that this data (hourly EAC purchases, hourly EAC sales, and hourly load) "is not a great indicator of this 'influence' of potentially CFS-ineligible generation assets required to serve load."[196] CMPAS pointed out such data will not capture:

- demand-response, which will decrease a utility's reliance on non-eligible CFS generation;
- batteries appearing as "load" each time they use MISO market energy to charge;
- a utility's reliance on CFS-ineligible generation if that utility is using net market purchases as part of CFS compliance—ie, CMPAS argues the data will simply reflect a utility's reliance on the market, not their reliance on CFS-ineligible generation;
- that certain Black Start carbon-intensive resources are going to have much longer system restoration times during emergency outages due to geographical isolation, unlike a highly connected area like the Twin Cities.

Minnesota Power noted that it is open to providing hourly data to specific customers seeking to meet their internal renewable energy goals, with the understanding that the cost of providing

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191 CEOs Initial at 13.

192 Basin Reply at 2. Basin was speaking to the legality of hourly matching, but Staff includes this here because it is relevant to hourly reporting.

193 Xcel Supplemental at 4.

194 Id. at 4.

195 CMPAS Reply at 11.

196 CMPAS Reply at 11.

such data would be the responsibility of the customer.[197]

2. Staff Analysis

Less of the record was devoted to hourly reporting than to hourly matching, and while Staff's impression is that hourly reporting is significantly more achievable than hourly matching, it would in part require all RECs/AECs to include an hourly-time stamp. It is not immediately clear whether this would be feasible or how long it would take for M-RETS to implement the systems necessary to track hourly data for all EACs.

Staff notes the Department's recommendation concerning REC/EAC reporting **(Decision Option 16)** is unclear as to the time interval. Currently EETS-obligated utilities report annual REC purchases, but this data is also currently, easily, and readily available as monthly data. Monthly data reporting is a potential option for the Department's recommendation for EAC reporting, or as an interim reporting recommendation if reporting utilities need a preparation time for a smaller reporting interval such as daily or hourly. To account for this, Staff added "or at the smallest time increment possible" into **Decision Option 16.**

Regarding the CEO's recommendation **(Decision Option 18)**, requiring utilities to estimate their carbon-free percentage on an hourly basis is a very similar task to actual hourly matching for compliance, albeit without the need to purchase and sell hourly RECs to achieve compliance in instances where a utility under-procures or over-procures carbon-free electricity, respectively. It is not clear how many of the Aligned Utilities reservations about hourly matching apply to the reporting of hourly data.

Should the Commission wish to proceed with hourly reporting, it may wish to consider the size of the utility required to report this information, as "all electric utilities" encompasses a range of utilities from investor-owned utilities to individual municipal utilities.

E. Hourly EAC Tracking and Certification

1. Commenter Positions

Google recommended the Commission direct utilities to investigate and implement systems to track and certify clean energy on an hourly basis. **(Decision Option 19)**.

Google explained that there is a need to pursue transparent hourly energy tracking to enable customers, utilities, and regulators to understand the granular dynamics of energy production and consumption. Both Colorado and Arizona have directed their utilities to investigate the implementation of time-based EACs (T-EACs), and Google explained that its own work, including a partnership with M-RETS to pilot hourly tracking, has demonstrated the feasibility

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[197] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Minnesota Power Supplemental Comments at 4 (April 16, 2025) (hereinafter "Minnesota Power Supplemental").

and benefits of T-EACs.[198]

2. Staff Analysis

Staff's understanding is that this recommendation can be pursued on its own or in conjunction with other hourly matching/reporting options. However, unless hourly data is being used for substantiating CFS compliance, Staff is unclear about whether the Commission has the authority to require this of non-regulated utilities. For this reason, Staff limited the decision to public utilities and put compliance parameters around **Decision Option 19**.

No other commenters weighed in on this, and so the Commission may wish to ask clarifying questions or entertain amendments or concerns from Google and other commenters on this matter.

F. Shelf Life of RECs/EACs

Modifying REC shelf life was a topic that emerged from the hourly matching discussion. Initially, and as one of a suite of recommendations to support an hourly matching construct, the Department recommended the Commission "rescind" previous Orders that allow RECs to be "banked" for a period of four years. After pushback from commenters in Reply Comments, the Department amended its recommendation in Supplemental Comments; instead, and upon suggestion from CSG, the Department recommended that those same previous Orders be "modified" to specify that the shelf life of RECs should be one year instead of four.

1. Commenter Positions

The Department's current recommendation is:[199]

> The Department recommends that the Commission modify order points 1 and 3 from its December 18, 2007 Order in Docket Nos. E-999/CI-04-1616 and E999/CI-03-869 and modify order point 6 of the Commission's December 6, 2023 Order in Docket E-999/CI- 23-151 to remove "All renewable energy credits generated from such facilities will be eligible for use in the year of generation and for four years following the year of generation," and replace the language with "All renewable energy credits generated from such facilities will be eligible for use in the year of generation and for one year following the year of generation." These orders will be modified effective January 1, 2030. [sic]
> **(Decision Option 20)**

Staff notes that Order Point 1 of the Commission's December 18, 2007 Order in Docket Nos. E-

198 Google Reply at 2-3.

199 Department Supplemental at 7-8.

999/CI-04-1616 and E999/CI-03-869 reads:

> The Commission hereby adopts a four year shelf life for all renewable energy credits that are to be used for compliance with the Minnesota renewable energy objectives/renewable energy standards. A four year shelf life means the renewable energy credit will be eligible for use in the year of generation and for four years following the year of generation.

Staff notes that Order Point 3 of the Commission's December 18, 2007 Order in Docket Nos. E-999/CI-04-1616 and E999/CI-03-869 reads:

> Renewable energy certificates used for green pricing programs will have the same four year shelf life as renewable energy credits used for compliance with the renewable energy objectives/renewable energy standards. Utilities shall clearly explain and document how the cost of renewable energy credits associated with green pricing programs are to be recovered.

Staff notes that Order Point 6 of the Commission's December 6, 2023 Order in Docket E-999/CI-23-151 reads:

> A hydroelectric facility greater than 100 MW may now be used for compliance with the renewable energy standard if the facility was in operation as of February 8, 2023. All renewable energy credits generated from such facilities will be eligible for use in the year of generation and for four years following the year of generation.

The Department argued that the Commission's language in its Orders indicates that those standards were not meant to be permanent. The Department specifically stated:

> The language used in the Commission's December 18, 2007 order suggests that its shelf-life decision was not intended to be permanent. The order was issued to establish "initial" protocols for trading RECs. In addressing the shelf life of RECs, the order outlines the different shelf-life proposals submitted by the parties then states: "The Commission considers a four year shelf life, added to the year of generation, *as a good place to start this process*." (Emphasis added.) And in rejecting the utilities' recommendation for an indefinite shelf life, the Commission stated that it, "at present does not believe that to be an advisable course" and would "not at this juncture" adopt such a recommendation. Note that the December 18, 2007 order was the second of three orders issued by the Commission in Docket Nos. E-999/CI-04-1616 and E999/CI-03-

> 869 to satisfy its statutory obligation to establish a program and protocols for trading RECs. The third order—which established procedures for retiring RECs—concluded by stating that the procedures would be "subject to modification in the light of future experience in implementing the Minnesota renewable energy objective and standards."[200] *[footnotes omitted]*

The Department stated that it does not believe that the Commission's decisions were wrong when made, but that there have been meaningful changes in technology, experience, and understanding about REC accounting since the Commission's protocol was adopted, and so general reworking of those protocols is warranted.

Xcel opposed the one year shelf life recommendation, stating that limiting a REC shelf life to one year goes against a long-standing, nearly 20-year precedent and should also not be considered.[201] Xcel argued that changing this precedent would penalize utilities that produce more than the number of RECs they need in a given year by preventing them from using these RECs at a later date, which could "incent utilities to deploy renewable resources slower than they would if the current precedent of allowing RECs to be carried forward remained."[202] Xcel also argued that changing this precedent would limit an important tool that utilities have to achieve their increasing targets in the most cost-effective way for their customers.

Other commenters disagreed with the Department's recommendation to modify the four year shelf life of RECs. CMPAS specifically recommended the Commission reject the Department's recommendation to modify the Commission's December 6, 2023 Order, and instead issue an Order indicating that RECs/AECs from carbon-free, non-renewable facilities will be eligible for use in the year of generation and for four years following the year of generation.[203] **(Decision Option 21)**

Some commenters focused specifically on the legality of the Department's recommendation. Basin,[204] CMPAS,[205] Great River Energy, and Xcel argue that the rescinding of the Commission's Order does not meet the standard for reconsideration required under Minn Stat § 216B.27 and Minn Rules 7829.3000. CMPAS also argued that Order Point 6 of the Commission's December 6, 2023 Order applied to the EETS (formerly RES), and did not mention the CFS, and is therefore outside the scope of this docket.[206] Basin argued that REC flexibility, including shelf life, has allowed Basin to maximize benefits to Minnesotans, which is required

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200 Department Supplemental at 4-5.

201 Xcel Supplemental at 5-6.

202 Id. at 6.

203 CMPAS Reply at 9.

204 Basin Reply at 2.

205 CMPAS Supplemental at 3.

206 CMPAS Reply at 9.

under Minn. Stat. § 216B.1691, subd. 9(a),[207] and that restricting REC shelf life would prevent maximizing benefits.[208] Xcel noted there remains a long-established precedent for the REC shelf life, and the legislature gave no indication that there was a desire to change that precedent.[209]

Commenters were also concerned about the policy and logistical implications of removing the four year shelf life. CMPAS noted that some of its members have long-term PPAs extending past 2030, and that many of these contracts could have RECs invalidated under a four year shelf life recission.[210] Great River Energy commented on the prospect of removing utility's ability to bank RECs for compliance, explaining that removing this flexibility would be "tantamount to a regulatory rug pull – removing well-established compliance strategies that utilities have been planning around, and potentially incurring tens of millions of dollars in lost value by rendering previously banked RECs worthless."[211] Basin stated that it has relied upon the Commission's four year shelf life in its process for allocating RECs to meet all of its compliance requirements across nine states.[212]

2. Staff Analysis

As noted in the Background Section of these Briefing Papers, the Commission's major considerations in establishing the four year shelf life were: 1. The uncertainty of a new program, and 2. The interest in not punishing early-adopters of renewable energy. To the second point, the reasoning was that if a utility built a renewable facility prior to the first compliance date, the utility should be able to carry those credits forward a certain length of time.

Staff notes the Commission's prior decisions to include language related to the REC shelf life in past Orders was to ensure consistency and reduce the need for parties to dig through over a decade of Orders to fully understand the Commission's current stance on the REC shelf life. The reiteration of the four year shelf life was not on the basis of merit, as this topic was simply not discussed until now.

Staff reminds the Commission that RECs retired for EETS compliance may also count toward CFS compliance. Because of this, any decision the Commission makes regarding the REC shelf life

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[207] Minn. Stat. § 216B.1691, subd. 9(a) states: the commission shall take all reasonable actions within the commission's statutory authority to ensure this section is implemented in a manner than maximizes benefits to all Minnesota citizens.

[208] Basin Reply at 1-2 and Footnote 1.

[209] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Northern States Power Company d/b/a Xcel Energy Reply Comments at 11 (March 19, 2025) (hereinafter "Xcel Energy Reply").

[210] CMPAS Reply at 3.

[211] Great River Energy Reply at 12.

[212] Basin Reply at 1.

should be consistent across all the REO Standards. There has been much discussion about the burden of compliance in this record, and Staff could see compliance becoming increasingly burdensome if utilities were required to consider the age of the RECs across several REO standards.

If the Commission should choose to reduce the REC shelf life to one year, the Commission may wish to incorporate the Department's consideration for a future implementation date so as not to punish utilities who have already procured RECs four years from now. However, the Commission does not need to amend past Orders to implement a future shelf life, and in fact doing so may inadvertently leave out existing Orders referencing a four year shelf life.

Further, to address the fact that RECs have monetary value, and to avoid erasing the monetary value of RECs that have already been generated, Staff would advise a phase-down approach in which RECs shelf life gradually decreases until it reaches the desired length. Phasing down the shelf life starting in 2030 would also avoid penalizing early adopters of carbon-free technologies, which was a concern in the years leading up to the SES' 2020 compliance date. For example, a phased-down approach could look like this:

2030: 4 year shelf life
2031: 3 year shelf life
2032: 2 year shelf life
2033: 1 year shelf life

While the Commission may consider retaining the REC shelf life, Staff notes that while Minn. Stat. § 216B.1691, subd. 4 specifies that "the commission must determine the period in which the credits may be used for purposes of the program," the REO statute does not require a REC shelf life. The shelf life was a tool created by the Commission to aid the early adoption of renewable technologies. The Commission's authority is broad on this front, and it would not be unreasonable for the Commission to review the plain language of the statute – which has been used to justify many arguments in this record – and determine that the language surrounding "annual sales" and annual generation does not support any shelf life. Staff reintroduces this argument, which was originally made by the Department, to highlight a path that the Commission could take if it feels compelled to take a step toward more a more accurate accounting ("annual matching") of Minnesota's carbon-free generation without adopting hourly matching. With this being said, since the inception of the REO all IRPs and all other reporting has used the four year shelf life, and there may be some unknowns relating to the impact of future compliance with a one year shelf life. Staff notes the Commission could consider changing shelf life at a future date if it needs more information on its impact.

G. Geographical Considerations

In the context of the CFS, "deliverability" refers to the idea that Minnesota customers should be delivered carbon-free energy and "attribution" refers to the idea that the energy being generated can reasonably attributed to Minnesotans or is serving Minnesota's load. CEOs made

a series of reporting recommendations aimed at promoting deliverability and Minnesota attribution.

Additionally, the Department initially made recommendations that would restrict utilities to generating or procuring only RECs/AECs located in the Midwest, but changed these to reporting requirements after commenter pushback. CSG recommended restricting EAC procurement to Minnesota or MISO North.

1. Commenter Positions

In its Initial Comments, CEOs recommended that the Commission take steps to ensure that the carbon-free energy used for CFS compliance can reasonably be attributed to Minnesota. The CEOs highlighted the language in the CFS that requires utilities to:

> "generate or procure sufficient **electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota** … so that the electric utility generates or procures an amount of electricity from carbon-free energy technologies that is equivalent to at least the following standard percentages of the **electric utility's total retail electric sales to retail customers in Minnesota**…"[213] (CEO added emphasis)

The CEOs argued that the plain language of the statute requires utilities to report the carbon-free electricity they can attribute to their Minnesota customers against their total Minnesota retail electric sales, and that including carbon-free energy that utilities provide to other states in their service territory or the regional market would violate the statute.[214]

As an example, they pointed to comments made by both Otter Tail and Xcel regarding how those utilities intend to calculate CFS compliance. Otter Tail stated that it would determine the amount of carbon-free electricity procured or generated in a calendar year, determine the Company's total retail electric sales to Minnesota customers, and calculate the percentage of electricity generated or procured from carbon-free resources in relation to the Company's total retail electric sales.[215] The CEOs explained that this methodology does not differentiate between the carbon-free electricity provided to Minnesota customers the electricity provided to customers of other states. Should utilities like OTP – with a significant share of their customers residing in different states – be able to attribute all of their carbon-free generation to Minnesota, it would obscure the amount of carbon-emitting generation they continue to depend on to meet Minnesota's electricity needs.[216]

On the other hand, Xcel recommended that utilities determine CFS compliance by reviewing

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213 Minn. Stat. § 216B.1691, subd. 2g.

214 CEOs Initial at 3.

215 OTP Initial at 3-4.

216 CEOs Reply at 5.

their Minnesota share of forecasted carbon-free owned generation and power purchase agreements divided by the forecasted Minnesota electric retail sales. The CEOs highlighted how this methodology does differentiate between carbon-free generation attributable to Minnesota and carbon-free generation attributable to other states.

However, CEOs contended that allowing carbon-free generation that utilities sell to MISO to count toward the CFS gives utilities an inappropriate incentive to maximize their net market sales due to the fact that they would be able to attribute such sales to Minnesota even if the carbon-free energy does not serve Minnesota. The CEOs cited a table from Xcel's 2024-2040 IRP that displayed the company would far exceed the 80% carbon-free requirement in 2030. Although Xcel confirmed that its predicted carbon-free generation for 2030 did not include MISO sales, the CEOs believe this not to be true and highlighted the need to specify that the carbon-free portion of MISO sales should not count toward CFS compliance.[217]

The CEOs recommended the following multi-part decision option that it claimed would require utilities to demonstrate that they have only attributed the Minnesota share of their carbon-free generation toward CFS compliance, explain the approach they used to attribute carbon-free generation to Minnesota, and retire RECs in the event that the utilities intend to rely on non-Minnesota carbon-free generation.

Decision Option 22: Through their annual REO reports, utilities must provide the following information:

A) The electric utility's predicted and actual rates of compliance with the Minnesota CFS, based on the statutory formula below:

$$\frac{\text{"electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota"}}{\text{"the electric utility's total retail electric sales to retail customers in Minnesota"}}$$

The utility should precisely explain how the numerator and denominator were calculated, and it must demonstrate that it has only included in the numerator carbon-free electricity (and/or applicable RECs) generated or procured to provide to retail customers in Minnesota (and therefore, that it has excluded electricity that serves customers in other states, that supports net sales to regional markets, or that is sold to other parties that are not Minnesota retail customers).

B) the utility's predicted and actual percentage of carbon-free generation on a system-wide basis. If the percentage of carbon-free generation claimed under the Minnesota CFS calculation in item A above is different than the percentage of

[217] CEOs Initial at 4-7.

carbon-free generation on the utility's total system, the utility should identify and explain the difference.

C) the utility's predicted and actual estimated line losses, including the basis for the estimate and an explanation of how those line losses affect the calculation under item A above.

D) the utility's predicted and actual sales to parties other than retail customers in Minnesota, specifically identifying net annual sales to regional markets, sales to retail customers in other states, and any other sales to parties other than Minnesota retail customers. The explanation should state whether the utility has sold the RECs associated with any of these sales if they are of carbon-free power.

E) the utility's predicted and actual purchase of RECs or retention of RECs from generation provided to non-Minnesota retail customers or from excess sales to MISO or other regional markets, identifying which are bundled and which are unbundled. RECs attributable to electricity generated or procured by the utility should be listed as bundled RECs, and those purchased from other parties where the energy associated with the REC was not purchased should be listed as unbundled RECs.

F) the predicted and actual CO2 emissions associated with all electricity generated or procured to provide retail customers in Minnesota, including emissions associated with the excess power generated or procured to cover line losses.

MLIG supported requirements C) and D) of the CEOs' recommendation, stating that this information would allow the Commission to "choose the least-cost option for compliance with the CFS"[218] and allow stakeholders to understand what resources are serving other jurisdictions.

Xcel opposed the CEOs' recommendation in its entirety, stating that CFS preparedness reporting should be a simple demonstration comparing forecast retail sales in Minnesota to forecasted carbon-free energy allocated to Minnesota. Staff notes that Xcel may have interpreted the CEOs' recommendation as one directed at CFS preparedness, where in fact it was intended for CFS annual compliance come 2030. Both the Department and Xcel weighed in on the topic of line losses, which is discussed in further detail in Discussion Section VII.H. below.

The Department noted that the CEOs' recommendation is generally not workable, since generator dispatch occurs through MISO and thus is "decoupled from Minnesota completely."[219] The Department further noted that restricting the "trading of renewable energy credits between states," is a violation of Minn. Stat. § 216B.1691, subd. 4.[220] The

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[218] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Minnesota Large Industrial Group Reply Comments at 3 (March 19, 2025) (hereinafter "MLIG Reply").

[219] Department Reply at 4.

[220] Id. at 4.

Department questioned line F of the CEOs' recommendation, explaining that even if fossil fuels are burned to supply Minnesota's energy needs while utilities work to achieve 100% carbon-free generation, the emissions associated with the use of those fossil fuels are nullified by the retirement of RECs to meet the CFS. The Department reiterated that the attribution of electricity to Minnesota is challenging, in part because power plants are dispatched by MISO to meet MISO load.[221] The Department agreed with the CEOs' concern but argued that the remedy lies instead in regional (rather than state) preferences for EAC purchases.[222]

To this point, the Department initially recommended that the Commission order all EACs used for CFS compliance be generated within the Midwest region. Without such a requirement, the Department explained that electric utilities could source carbon-free power anywhere in the country regardless of whether the power had the chance to physically meet the state's energy needs. To define the "Midwest region" the Department looked to the IRS 45V tax credit for hydrogen, which the Department stated ensures that carbon-free power generation is realistically capable of meeting local energy needs.[223] The 45V regulation defines MISO North and MISO Central/South separately to reflect the transfer constraints between the regions.[224]

Zero Lab found support for the Department's initial recommendation in its analysis, stating "In the absence of additional demand for hourly-matched clean power, tighter regional boundaries on procurement can increase both the cost and emissions benefits of an hourly matching policy. Both cost and impact are moderate when a MISO North boundary is used, and become more significant when only use of in-state clean resources is permitted."[225] EnergyTag agreed with the comment made regarding tighter deliverability zones driving greater decarbonization impacts, especially within Minnesota.[226]

CSG agreed with statements made by CEOs and the Department regarding the need for a deliverability requirement, noting that deliverability is a crucial issue when designing a REC-based program because REC eligibility criteria will ultimately determine the targets for capital allocation.[227] CSG contended that like double counting and double claiming, non-delivery of carbon-free energy to Minnesotans could undermine the Commission's obligation under Minn. Stat. § 216B.1691, subd. 9(a)(4) to take all reasonable actions within its statutory authority to ensure the implementation of the REO standards maximizes net benefits to Minnesotans. CSG

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221 Id. at 11.

222 Id. at 5.

223 This tax credit requires that electric generation used to generate hydrogen be sourced from a facility in the same region, with several exceptions. If energy is not sourced from a facility in the same region, it must use the regional power mix. Interregional EAC transfers are permitted provided that 1) the owner of the EAC has transmission rights outside of the region, 2) the owner settles the transaction within the region, and 3) the owner does not have any reverse transactions to counteract the sale.

224 Department Initial at 13.

225 Zero Lab Supplemental at 7.

226 EnergyTag Supplemental at 12

227 Department Initial at 13.

argued that although the issue is complicated by language in Minn. Stat. § 216B.1691, subd. 4 that requires EAC trading between states, the reality is that California-sited generation does not have a measurable impact on the electricity delivered to Minnesotans. CSG therefore recommended that CFS-eligible resources be limited to generation located within Minnesota or MISO North **(Decision Option 23)**.

Many arguments raised in opposition to the Department's withdrawn recommendation are relevant to CSG's standing recommendation, and so Staff has included them here.

Xcel disagreed that CFS-eligible generation should be geographically limited, noting that there is no indication in Minn. Stat. § 216B.1691 that the intent of the CFS was to limit the location of generation resources used to demonstrate compliance with the CFS to MISO North or to Minnesota.[228] Xcel also made a conceptual argument about EACs, noting that greenhouse gasses are a global pollutant, and so limiting EAC purchases to just the Midwest would have no added benefit to the environment.

MRES also opposed the Department's recommendation and asserted that the legislature also specifically granted utilities the ability to meet REO standards with RECs, which are separate and distinct from energy, and specified that RECs are able to be traded between states.[229] MRES also noted:

> Further, requiring delivery of the energy associated with the RECs into the MISO Midwest footprint would unduly burden entities that have built renewable facilities outside MISO. MRES' Pierre Solar Project and Brookings Solar Project (currently under construction) are both located in South Dakota within the Southwest Power Pool footprint. It is not financially feasible for MRES to purchase transmission service between SPP and MISO for these solar energy projects. MRES believes the RECs associated with the energy produced from these projects should count toward CFS compliance, just as they currently count toward compliance with the EETS.[230]

Basin noted that it relies upon RECs from generation resources in both the US and Canada.[231]

Minnkota did not specifically address EAC geographical considerations but expressed general concerns about dormant Commerce Clause issues.[232]

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[228] Xcel Supplemental at 2.

[229] MRES Reply at 3-4.

[230] MRES Reply at 3-4.

[231] Basin Reply at 1.

[232] Minnkota Reply at 3.

CMPAS noted that the Department's recommendation conflicted with Minn. Stat § 216B.1691, subd. 4(a), which states "[t]he program must treat all eligible energy technology equally and shall not give more or less credit to energy based on the state where the energy was generated or the technology with which the energy was generated." CMPAS recommended the Commission issue an Order Point that EACs from any location are allowed to be used for EAC compliance, as long as those EACs meet all other eligibility requirements for CFS.[233] **(Decision Option 24)**

CMPAS also stated that the Department may not be aware of the reasons that a utility would retire EACs from regions outside of the Midwest, and provided several examples for the record:[234]

1. The utility is one of several utilities who contract for physical energy from a set of large generators of the same type in various locations. Since it is not always possible to tell exactly which generator has delivered the actual, physical energy to each utility, the generator owner provides RECs from any of generators to any of the utilities. Example: Power from Western Area Power Administration (WAPA) hydropower reservoir dams.
2. The utility has traded more expensive EACs originating from its contracted renewable or carbon-free generation in the Midwest Region with less expensive EACs originating from generation in a different location.
3. The utility has a PPA with a counterparty for EACs bundled with physical energy from a specific carbon-free generator in the Midwest Region. The PPA counterparty has failed to deliver at contractual minimum levels and provides the utility with replacement energy from the MISO Market and unbundled EACs from a different location outside the Midwest Region.
4. The utility truly does not have physical delivery for any energy from a renewable or carbon-free resource in the Midwest Region.

The Department appears to have been most persuaded by the REO statutory requirement that RECs not be given more or less preference based on the state where the energy was generated, but notes that parties raised many compelling arguments.[235] The Department withdrew its initial recommendation and instead made the following recommendation:

> The Department recommends the Commission order all procurements of physical assets, PPAs, and any other contract that involves EACs necessary to meet Minn. Stat. § 216B.1691 compliance requirements be subject to the following geographic preference reporting requirements at the time the procurement decision is proposed:
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> A. Procurements Within Minnesota:

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233 CMPAS Reply at 9.

234 CMPAS Reply at 11-12.

235 Department Supplemental at 41.

1. The number of EACs expected to be procured each year.

B. Procurements in Counties or Municipal Divisions Bordering Minnesota:

1. The number of EACs expected to be procured each year.
2. The state and county or municipal division and country of procurement.

C. Procurements in the MISO territory of Non-Border Counties of North Dakota, South Dakota, Iowa, Wisconsin, and Manitoba:

1. The number of EACs expected to be procured each year.
2. The state and county or municipal division and country of procurement.
3. Explanation of any technical, cost, or other constraints that preclude a procurement under A. or B.
4. Explanation of any local benefits including jobs, tax revenue, other economic factors, air quality, and environmental justice considerations that will not be received by Minnesota ratepayers.

D. Procurements in all Other Locations:

1. The number of EACs expected to be procured each year.
2. The state and county or province of procurement.
3. Discounted cash flow that demonstrates why a procurement under A., B., or C. is financially harmful to Minnesota ratepayers.
4. Technical analysis of why there is insufficient transmission, siting, or unbundled EAC availability under A., B., or C.
5. Quantification of any local benefits including jobs, tax revenue, direct and indirect economic factors, air quality, and environmental justice considerations that will not be received by Minnesota ratepayers

(Decision Option 25)

The Department provided this recommendation in Supplemental Comments, and so no other commenters have weighed in.

2. Staff Analysis

Minnesota has a strong history of siting renewable and carbon-free generation within the state when possible. However, Staff also agrees that the REO statute clearly permits REC trading between states, which indicates that RECs from other states may be used for compliance, and notes that out-of-state RECs have been eligible for compliance for many years. The Commission clarified in 2004 that out-of-state generation may be used to meet REO objectives so long as those facilities are used to serve Minnesota customers. No party to any of the proceedings since 2004 has requested the Commission reverse its decision, until now. It is not clear why this decision should be changed at this particular point in time.

Staff notes that the CEOs recommended their reporting requirements occur in annual REO reports. However, the Department's reporting recommendation only notes that it is "at the

time the procurement decision is proposed." Should the Commission wish to approve **Decision Option 25**, Staff recommends the Commission confirm with the Department whether this would be filed with the annual REO reports or at some other time.

H. Line Losses

1. Commenter Positions

As part **of Decision Option 22**, CEOs recommended that utilities be subject to reporting on line losses. The Department supported the CEOs in this and highlighted the following modification made to the EETS by H.F. 7:

> Subd. 2a. Eligible energy technology standard.
> (a) Except as provided in paragraph (b), Each electric utility shall generate or procure sufficient electricity generated by an eligible energy technology to provide its retail customers in Minnesota, or the retail customers of a distribution utility to which the electric utility provides wholesale electric service, so that the electric utility generates or procures an amount of electricity from an eligible energy technology that is equivalent to at least the following standard percentages of the electric utility's total retail electric sales to retail customers in Minnesota ~~are generated by eligible energy technologies~~ by the end of the year indicated…

The Department asserted that adding "equivalent to" the statute decouples generation from total retail electric sales by the addition of equivalence, and thus allows the Commission to determine that generation should serve load and not merely match load.[236] The Department explained that accounting for line losses is already standard practice in utility IRPs, and that without accounting for line losses, some portion of the energy utilities provide customers could still come from CFS ineligible sources. For example, the CEOs found through an information request attached to their initial comments that Xcel anticipates line losses of up to 9.66% in 2030. To resolve this issue, the Department recommended that the Commission Order CFS and RES compliance measurements to factor in line losses to determine compliance with each standard. **(Decision Option 26)**

Xcel disagreed with the Department, arguing that incorporating line losses into preparedness and compliance demonstrations would be in direct conflict with longstanding practice of awarding RECs based on actual generation and using the awarded RECs to meet statutory obligations based on retail sales. Xcel further argued that the statute gave no indication that the legislature intended to deviate from the precedent established with EETS compliance. Xcel also argued that incorporating line losses would require the development of a complicated

[236] Department Reply at 10.

accounting mechanism to track and determine accurate line losses and would subsequently require additional REC retirements; this would effectively result in the loss of approximately 10 percent of RECs that are available for compliance, adding to the cost of compliance, and higher retirement fees, and thereby affecting customer costs.[237]

2. Staff Analysis

According to the Department, its recommendation is actionable due to the modifications made to the EETS by H.F. 7. Staff's read of the amendment made by H.F. 7 differs significantly from the Department's. It would appear to Staff that the intent of this amendment was to correct a grammatical error. In the initial language, "utility's total retail electric sales…" were "generated by eligible energy technologies." While parties have had no problem interpreting this statute in the past, it could very easily be read as though the *technologies* were being required to generate sales. The amendment referenced by the Department resolves this issue, and in Staff's view adds more clarity, affirming the current process, whereas the Department's argument is that the language change makes the statute vaguer and more open to new interpretation.

Should the Commission decide to move forward with a calculation of line losses as a part of CFS compliance, Staff would recommend taking additional comment specifically on this issue. There is not currently a record on how line losses would be applied to individual facilities, or the RECs they generate. Because all of our compliance accounting involves utilities owing and retiring credits, the impact of line losses would likely need to be accounted for by either modifying the number of credits each utility owes (increasing the "total retail electric sales" by some factor to simulate line losses), or reducing the credits that are generated. Further, the Department's recommendation only applies to the EETS and CFS while ignoring line losses for the DSES and SES. Should the Commission choose to move forward with a line-loss discussion, it should not arbitrarily address only the CFS and EETS while ignoring the DSES and SES.

I. Clean Transition Tariff

1. Commenter Positions

Google recommended directing utilities to establish a clean transition tariff (CTT) which they described as an optional electricity tariff that allows users to pay for the incremental cost of accelerating clean energy deployment in exchange for capacity, energy, and environmental attribute credits provided by the resource to the system.

Google described CTTs as "innovative rate structures designed to accelerate clean energy deployment by leveraging private capital" and that "enable large electricity customers to directly support new clean energy resources through specialized agreements with their utility" in which they commit to pay for energy generated by one or more dedicated, newly procured clean resource.[238] Any energy consumption beyond what is generated by the CTT resource

[237] Xcel Supplemental at 3-4.

[238] Google Reply at 3.

would be billed at the applicable rate.

Key Features Include:

1. new incremental clean energy resources
2. economic dispatch as part of the utility's portfolio
3. capacity and attribute allocation to the customer
4. customer protections to prevent cost shifting

Xcel noted that it is interested to work with Google on investigating the development of a "Clean Transition Tariff" and expects the Commission's forthcoming Order in Docket No. E-002/RP-24-67 will require Xcel to do this. In that docket, Xcel noted that the Commission adopted an order point requiring Xcel to consult with the Department to consider filing a voluntary carbon-free electricity (CFE) procurement program that enables more customers to achieve annual CFE goals. As such, Xcel believes the development of a CTT in the CFS Docket would be redundant.[239]

2. Staff Analysis

Staff notes that the Minnesota Legislature recent passed an energy bill incorporating a CTT.

> Sec. 10. [216B.1623] CLEAN ENERGY AND CAPACITY TARIFF.
> The commission shall require each public utility to offer a clean energy and capacity tariff for commercial and industrial customers. The clean energy and capacity tariff shall require a special contract between the utility and one or more customers that shall:
> (1) be optional for participating customers;
> (2) permit participating customers to elect to serve some or all of their energy or capacity usage from new clean energy or capacity resources as long as reliability is maintained;
> (3) require the participating customers to pay all proportional costs associated with the addition of the new clean energy or capacity resources including any utility costs caused by the addition of the new clean energy or capacity resources to the grid;
> (4) develop an appropriate energy and capacity credit;
> (5) prohibit cost shifting from the participating customers to other utility customers or vice versa; and
> (6) allow a utility with an applicable tariff on file to demonstrate their existing tariff's compliance with this section.
> EFFECTIVE DATE.

[239] Xcel Supplemental at 6.

This section is effective the day following final enactment.[240]

Since the legislative changes appear to have made the proposed decision option redundant, Staff has not provided a CTT Decision Option. Staff notes, however, that many of the utilities subject to the REO and CFS do not file tariffs—only Xcel, Minnesota Power, and Otter Tail Power.

J. Net Market Purchases: Average Fuel Mix vs. Residual Mix Accounting

For purposes of the CFS, average fuel mix accounting first totals annual generation in MISO North (for example), then totals the annual generation in MISO North that comes from resources the Commission determines to be either fully or partially carbon-free.[241] The percentage of carbon-free generation of total generation would be considered the average carbon-free fuel mix for that year.

By contrast, residual mix accounting first totals annual generation in in MISO North and removes any generation associated with known REC/AEC/EAC claims. The remaining generation is considered MISO North's "residual mix." The percentage of carbon-free generation within the residual mix would be the percentage that could be counted as carbon-free.

Residual mix accounting can also happen at the entity-level. For purposes of the CFS, a utility totals its retail sales for a year (includes generation, market purchases/sales, PPAs/VPPAs, and any other relevant contractual purchases and sales) and removes any known REC/AEC/EAC claims from its own total. The remaining utility sales would be considered a "utility-specific residual mix." The percentage of carbon-free generation within the residual mix would be the percentage that could be considered carbon-free.

The main purpose behind residual mix accounting is to avoid double-claiming of environmental attributes.

The Commission's provisional guidance from its November 7th Order indicated a move towards average fuel mix—rather than residual mix—accounting. However, the Commission is not locked into this path should it determine residual mix accounting is in the public interest. To a point, either method can be paired with the Commission's determination on credit-based versus energy-based claims (discussed in Discussion Section VI.C. above).

Regardless of the Commission's decisions in this docket, the Commission will determine the degree to which complex fuels such as biomass and hydrogen count as carbon-free in the context of net market purchases in the LCA Docket.

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[240] See Chapter 12 - MN Laws, Section 10.

[241] The degree to which certain complex fuels such as biomass and hydrogen are considered eligible for carbon-free compliance in the context of net market purchases will be addressed in the Commission's LCA Docket.

1. Commenter Positions

a. Average Fuel Mix Accounting

Average fuel mix accounting found support amongst utilities. Connexus,[242] Great River Energy,[243] MRES,[244] Otter Tail Power (OTP),[245] and Xcel[246] supported a simple, straightforward approach for calculating net market purchases, one in which the utility multiplies its net market purchases—purchases in excess of sales—by the percentage of carbon-free energy in MISO North's fuel mix for a given year.

Connexus was opposed to residual mix accounting; the cooperative argued that this recommendation does not adhere to a plain language interpretation of statute.[247] Connexus argued that there is no reasonable interpretation of the plain language of the statute that requires net market purchases to be calculated based on a utility-specific residual mix, since the statute clearly states that the carbon-free portion should be based on the RTO's system or subregion.

b. Residual Mix Accounting

Both CRS and CSG recommended that net market purchases be calculated by using residual mix accounting. Both commenters also recommended the Commission require utilities to retire RECs, AECs, or equivalent EACs to substantiate their net market purchases for CFS compliance purposes; however, Staff reiterates that residual mix accounting can be used absent that recommendation, to a point.

CSG argued that the statute is ambiguous regarding what constitutes a "subregional fuel mix," stating that other commenters may argue for the use of a MISO subregion such as MISO North, but that "subregional fuel mix" could also be thought of in non-geographical terms. CSG argued that the use of the term "subregional fuel mix" does not necessitate the use of these specific subregions over other options.[248]

CSG cautioned, however, that net market purchases could only count towards CFS compliance to the extent that a MISO residual mix still contains carbon-free attributes that have gone unclaimed; in the event that none remain, the percent of carbon-free would be zero.[249] Further, any remaining unclaimed carbon-free electricity in the regional residual fuel mix may

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242 Connexus Initial at 3.
243 Great River Energy Initial at 3.
244 MRES Initial at 4.
245 OTP Initial at 5.
246 Xcel Initial at 8.
247 Connexus Reply at 2.
248 CSG Initial at 27.
249 CSG Initial at 2.

have been claimed by an entity outside of the subregion.

Commission Staff noted the following in its September 12, 2024 Briefing Papers:

> CRS and MRES disagreed about whether generation due to PPAs should be removed from the applicable market fuel mix when calculating compliance through net market purchases. CRS recommended that emissions and sales associated with PPAs should be removed from the applicable market fuel mix (either system-wide or subregional), thereby creating a utility-specific residual mix.
>
> Staff was unclear whether CRS was recommending removing emissions and sales associated with all PPAs in a given market footprint, or only those PPAs in which that utility takes part. If the recommendation is the former, Staff notes that this is likely not possible in the MISO market; Staff's understanding is that there is no centralized location in MISO where all PPA sales are tracked. Instead, individual PPA information is tracked by the participating parties. Therefore, if the recommendation is the latter (that each utility should remove emissions and sales associated with their own PPAs to create a utility-specific residual mix), this would be feasible. Further, Staff is unclear about how CRS proposes to treat instances where a vertically-integrated load-serving entity is paying itself at MISO.[250]

Staff recommended further record development on this issue, and the Commission agreed.[251]

In the instant Round 3, CRS highlighted that utilities could use potentially use a residual mix reported by the U.S. EPA for the subregion under the EPA's Emission & Generation Resource Integrated Database (eGRID) where the utilities' operations are located.[252] However, in Reply Comments, CRS clarified that it supports the use of whatever the most accurate residual fuel mix might be at a given time, and noted that MISO and M-RETS will be the best sources of data for market residual mix accounting.[253] To Staff's prior question, PPAs would only be necessary to remove in residual mix accounting insofar as they are associated with RECs/AECs/EACs; it is the generation associated with claims themselves that would be removed. **Decision Option 27** directs utilities to calculate net market purchases using a market residual mix.

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[250] Staff September 12th Briefing Papers at 78-79.

[251] November 7, 2024, Order Initiating New Docket and Clarifying "Environmental Justice Areas," Docket No. E-999/CI-23-151 at 4.

[252] CRS Initial at 8-11.

[253] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Center for Resource Solutions' Reply Comments at 3 (March 19, 2025) (hereinafter "CRS Reply").

Both CRS[254] and the Department[255] contemplated an annual process by which MISO, M-RETS, or an independent contractor aggregate data and use it to calculate and make available an official market residual mix. Each utility could then use this to determine how much of its net market purchases may be applied for compliance with the CFS. However, the Department ultimately concluded that such a process would be costly and time-intensive, noting that "the administrative burden does not appear to be worth the potential revelation that there may be no residual RECs to claim at all."[256]

CSG explained that the most accurate way to calculate a residual mix is to calculate the residual mix of all obligated entities in the chosen market footprint (eg, LRZ 1, MISO North, or MISO Systemwide).[257] This would entail adding up each obligated entity's PPAs, VPPAs, unbundled RECs, and other contractual transfers of exclusive emissions claims that might not register under the accounting of market-based net purchase data. Through this process, the residual mix of each utility would also be calculated—ie, a utility-specific residual mix. CSG recommends the use of a utility-specific residual mix. **(Decision Option 28)**

From Staff's understanding of CSG's recommendation, the market residual mix would not actually be used; instead, each utility would have its own utility-specific residual mix that it would calculate from its own data sources.

c. MISO North as Preferred Subregion

To build on the Commission's November 7th Order, CEOs recommended the Commission specify that it will use the fuel mix of the MISO North subregion (Local Resource Zones 1-7) when calculating partial compliance credit for net annual MISO purchases. **(Decision Option 29)**. OTP, GRE, and Xcel also expressed a preference for the MISO North subregional fuel mix.[258]

CSG noted that a smaller subregion calculation (such as an LRZ) will be inherently more accurate than a systemwide calculation, due its tighter parameters; however, without residual mix accounting, any calculation is going to be flawed.[259]

2. Staff Analysis

Staff agrees that there could be benefit to residual mix accounting, but also notes potential pitfalls.

Utility-specific residual mix accounting, as recommended by CSG, may be administratively easier, as utilities would be using their own known data. Conceptually, however, Staff finds

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254 CRS Reply at 4.

255 Department Supplemental at 47.

256 Department Supplemental at 47.

257 CSG Initial at 6.

258 OTP Initial at 5, Great River Energy Reply at 8, Xcel Initial at 8.

259 CSG Initial at 6.

utility-specific residual mix confusing in the context of net market purchases, as it only appears to make sense when paired with the requirement that net market purchases be accompanied by EACs.

Staff can more readily understand the rationale behind removing known EAC retirements from a market fuel mix when calculating net market purchases, as recommended by CRS. As noted by the Department, however, the calculation and administration of a market residual mix could be unduly burdensome to utilities or other stakeholders and may yield no benefit.

Should the Commission wish to pursue some form of residual mix accounting, it might consider a hybrid approach by requiring utilities to use an average market fuel mix, but remove generation associated with their own EAC claims. Utilities would more readily have access to this data, and this would address the Department's concern mentioned earlier that "if an electric utility claims net market purchases of the fuel mix for CFS compliance, it would be claiming a fraction of its own carbon-free generation, unless this generation is subtracted from the fuel mix."[260]

Finally, Staff notes that although the Commission may specify that the MISO North fuel mix be used for purposes of calculating net market purchases, as in **Decision Option 29**, the Commission may also find this unnecessary. This is because, as worded, the Commission's directive for utilities to "Calculate the percentage of carbon-free market purchases using an applicable regional transmission organization subregion—using annual energy fuel mix data—as practicable" means that utilities participating in MISO will calculate net market purchases using MISO North data, whereas utilities participating in SPP will use systemwide data. This has to do with what data sources are currently available.[261]

K. Enhanced Auditing

1. Commenter Positions

The CEOs recommended that the Commission request the Department conduct enhanced auditing of REO reports ensure electric utilities are making sufficient progress toward compliance;[262] the Department recommended the Commission direct Commissioner of Commerce to seek authority from the Commissioner of Management and Budget to incur costs for specialty services to provide auditing of all CFS reports for up to three years. (**Decision Option 30**) In response, CMPAS voiced concern about a request for "rigorous audits" and stated that any audit should follow an established process with input from utilities; CMPAS does not object to an audit, but wants there to be an opportunity to answer questions during an audit process or clarify information about itself or any of its small municipal utility members.[263]

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[260] Department Initial at 24.

[261] For a further discussion of this, Staff September 12th Briefing Papers at 75-77.

[262] CEOs Initial at 18-19.

[263] CMPAS Supplemental at 4-5.

(**Decision Options 31**)

2. Staff Analysis

Staff notes that both the Department and Staff already provide some degree of "audit" of annual REO reports, simply through the review, compilation, and reporting of utilities' annual and biennial filings. Staff is unclear exactly what an "enhanced" audit would entail and whether such an enhancement is necessary. Staff further notes that these reports are publicly available after they are annually filed on June 1st in Docket No. E-999/PR-YR-12, and that any party may conduct an audit of the available information, or of the Department's analysis. Staff has included Decision Options to accompany the enhanced audit recommendations, but notes that the Commission may wish to solicit further information from parties about exactly what benefits could result from an enhanced audit process, and how they would fundamentally differ from the current process. Further, the authority under Minn. Stat. § 216B.62, subd. 8 to incur costs for specialty services only applies to public utilities (Xcel, MP, and OTP), not the many other cooperative and municipal utilities subject to these requirements so it is now clear how this logistically or financially would be implemented.

L. Request for Common Definitions and CFS Implementation Workgroup

1. Commenter Positions

CMPAS noted that the terms "bilateral contract" and "power purchase agreement" have been used interchangeably in this docket, and in particular in the Commission's November 7th Order. CMPAS noted the following:

> [m]any in the electric industry who are involved in power trading and energy transactions use the term 'bilateral contract' to refer to contracts exclusively for capacity (i.e., sale of 'Zonal Resource Credits') where no energy is included in the contract for actual purchase by the buyer.[264]

CMPAS requested the Commission adopt a formal definition of "bilateral contract" and other terms in the context of CFS compliance to ensure a common understanding between commenters. CMPAS identified the following additional terms as needing clarity: bundled EAC, unbundled EAC, specified purchase, unspecified purchase, specified resource. (**Decision Option 32)**[265] The Department stated that it interprets the Commission's use of the term "bilateral contract" to refer specifically to bilateral contracts involving the purchase of energy by a utility, while acknowledging that bilateral contracts can also involve capacity. The Department cited Minnesota's Power's petition to recover costs stemming from a bilateral contract involving the

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[264] CMPAS Initial at 7.

[265] CMPAS Supplemental at 9.

sale of both capacity and energy, Docket No. E-015/M-22-501.[266]

CMPAS also requested the creation of a Commisison-led workgroup to assist commenters with the implementation of CFS compliance, once all Orders for this docket have been issued.[267]

2. Staff Analysis

Staff agrees with the Department's interpretation that bilateral contracts can include energy purchases. However, if the term "bilateral contract" is thought by parties to be specific to capacity-only contracts, then its use in the Order Point appears to be merely excessive language, and its inclusion would not substantively change the meaning of the Order Point. Since the referenced Order Point was provisional, Staff suggests the Commission leave the language as it stands for the time being; should the Commission affirm this Order Point at a future time, Staff can propose to remove the term "bilateral contract" at that time, if necessary.

Staff agrees generally with CMPAS on the importance of standardized terminology. However, given commenters' diversity of experience and backgrounds, it may be unlikely commenters would implement standardized terminology, even if such a list of common definitions is formed. Although sometimes confusing, Staff does not necessarily consider the misuse of terminology to be a negative, as it's important for these proceedings to be as accessible as possible to the public. In Staff's opinion, the best course of action commenters can take is to be as clear as possible about the meaning behind any terminology used in a given document. Furthermore, it is incumbent upon commenters to file comments noting needed corrections in Staff's briefing papers—including these current Briefing Papers—if errors in terminology or content are found.

Nonetheless, Staff has included **Decision Option 32** to address CMPAS's concerns. Staff notes that CMPAS did not provide a suggestion for how the Commission should agree upon a common set of terms, and so Staff provided one. Should the Commission wish to pursue **Decision Option 32**, the Commission may wish to ask CMPAS for any clarifications or amendments during the Agenda Meeting.

Finally, Staff also recognizes the need for guidance when parties file REO compliance, particularly when new requirements are implemented or when obligated entities have fewer resources to dedicate to REO compliance. However, Staff disagrees that a CFS implementation workgroup is necessary. When utilities need help filing, they are encouraged to reach out to Commission Staff member identified on the notices in the YR-12 dockets. Staff is available throughout the year to offer guidance, but is especially available prior to the June 1st filing deadline. Staff is unable to provide legal advice, but can point parties to relevant Commission Orders and statutes. A workgroup would not expand Staff's ability to advise parties, as it would still would not be able to provide legal or otherwise speak on behalf of the Commission in the

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[266] Department Reply at 21.

[267] CMPAS Initial at 7.

context of a workgroup. Therefore, Staff has not included a Decision Option on this point.

VIII. Topics Outside the Scope of this Round/Docket

Commenters brought up a number of issues that are outside the scope of the CFS Docket, better discussed in Round 4 of the CFS Comments, or better discussed in the LCA Docket.

A. Contract Off-Ramps

1. Commenter Positions

CMPAS recommended that the Commission clarify that RECs or AECs from existing contracts be eligible for CFS compliance beyond 2030. **(Decision Option 33)** CMPAS explained that the need for this clarification comes from a need to ensure utilities are not penalized for the early adoption of renewable energy and forced to purchase carbon-free energy twice.[268]

2. Staff Analysis

Staff notes that CMPAS's **Decision Option 33** is very broadly worded and lacking in context; as such, Staff advises the Commission against adopting **Decision Option 33** until CMPAS provides more information about the specific situation that needs to be addressed. Staff is sympathetic to the fact that the Commission's current proceedings might bring CFS compliance uncertainty to utilities who have existing long-term energy contracts extending beyond 2030. However, Round 4 in the current proceedings (off-ramps) will address issues where utilities may be granted compliance exceptions. Staff recommends CMPAS more fully discuss the specific issue in that round of proceedings and develop a more tailored decision option at that time.

B. Cost and Reliability Reporting

1. Commenter Positions

Referencing requirements under Minn. Stat. § 216B.1691, subd. 2e, the Minnesota Large Industrial Group (MLIG) recommended that the Commission require all electric utilities to file:

- A reference case scenario, detailing the least cost plan, from a ratepayer impact perspective, for meeting the CFS by 2040 and 2050; and
- A reference case scenario, detailing the least cost plan, from a ratepayer impact perspective, to partially meet the CFS by 2040 and 2050.
  (Decision Option 34)

MLIG argued that these reference case scenarios would provide the Commission and parties with the information they need to understand the utility's preferred plan versus other possible plans, with the ability to evaluate the least cost way of meeting the CFS' 2040 target and the

[268] CMPAS Reply at 3.

cost mitigation that could result if utilities partially met the 2040 target. Further, MLIG requested that the Commission provide both utilities and customers with some expectation as to what is a "reasonable" cost increase for complying with the 2040 target. MLIG stated that this explanation would provide guidance to utilities as they prepare their IRPs and provide a reference for future proceedings.[269]

MLIG also requested that the Commission establish:

- reporting requirements to evaluate how compliance with the EETS, SES, and CFS impact system reliability.
  (Decision Option 35)

MLIG stated that this report should analyze the findings available in their current reliability filings, determine whether implementation of the 2040 bill caused reliability impacts, and file an annual report to outline any necessary changes to their implementation plans to maintain reliability.

The Department provided mixed support for the proposal. The Department concluded that studying a delay in the CFS is practical and useful for decision-making purposes but MLIG's proposal is too long and not tied to the typical five-year IRP action plan. The Department did not support MLIG's proposal to study partial compliance, which is "more extreme in nature and is far more open-ended."[270] The Department noted that studying partial compliance could add significant complexity to IRP scenario planning, and MLIG had not proposed a framework to study partial compliance. Regarding MLIG's discussion of the reasonableness of rates, the Department stated that there is no need for further clarification about ratepayer impacts which are covered by existing IRPs, and that request for clarification regarding the off-ramp process for the REO standards should come in the next round of comments focused on that topic.

LIUNA agreed with Department's conclusion that MLIG's rate impact assessment requests are duplicative and unnecessary; LIUNA also agreed with the Department that an analysis of a five-year delay to the CFS would be reasonable.[271]

Xcel noted that MLIG's cost reporting requirements would serve as a basis upon which the Commission could evaluate the necessity of off-ramps and other mitigations to maintain affordability; as such, Xcel recommended MLIG's proposal be discussed in greater detail in Round 4 of the CFS comments.[272]

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269 MLIG Initial at 2-3.

270 Department Reply at 16.

271 LIUNA Supplemental at 1-2.

272 Xcel Supplemental at 5.

2. Staff Analysis

Staff notes a number of other issues surrounding MLIG's proposal that parties have not commented upon:

- MLIG's recommendations focus primarily on the CFS, when Minn. Stat. § 216B.1691, subd. 2e states that this reporting should evaluate the rate impacts to comply "with this section" indicating that utilities should report on the costs to comply with all of the REO statutes and not just the CFS. If the Commission is not satisfied with the current level of reporting in response to Subd. 2e, it could include this topic in comment Round 4 of this docket.
- MLIG's reference to "reference case scenarios" and "ratepayer impact perspectives" implies a focus on electric utilities that file IRPs with the Commission, but many utilities who must comply with the REO statute do not file IRPs but would still be expected to provide a scenario analysis under this recommendation.
- MLIG requested that the Commission predetermine what cost increases would be reasonable for achieving the 2040 target for future reference. Staff has general concerns about pre-determining "reasonable costs" for 2040 in July of 2025, as much can transpire between today and 2040 that may change our opinion on what is "reasonable". The off-ramp process was written such that individual utilities could petition the Commission for a modification of the standard and provide evidence on the unreasonable costs required to fully comply with the standard, which the Commission must consider under Minn. Stat. § 216B.1691, subd. 2b.
- MLIG's reliability reporting recommendation goes beyond statutory compliance requirements. Utilities that are experiencing or are able to predict reliability issues resulting from REO compliance may petition the Commission to modify their standard obligations under Minn. Stat. § 216B.1691, subd. 2b. While reviewing this petition, the Commission must consider the effects of implementing the standard on the reliability of the electric system.

As discussed in the Background Section of these Briefing Papers, in the past the Commission has determined that the REO's impact on rates would be best handled through utilities' rate cases, and that the annual reliability reporting requirements[273] would adequately apprise the Commission and stakeholders of any utility-specific drops in reliability.[274] The Commission recognized that not all utilities subject to the REO file rate cases, and stated that it would accept voluntary filings on the rate impacts of the REO in utilities' biennial compliance reports.

Staff notes that this Decision was made fifteen years ago, there has since been an influx of new "electric utilities' subject to these standards who either may not file rate cases or IRPs. Staff notes the Commission's prior Order on this matter may no longer be appropriate, but also has

[273] Contained in Minnesota Rules Chapter 7826.

[274] March 19, 2010 Order Clarifying Criteria and Standards for Determining Compliance Under Minn. Stat. § 216B.1691, Docket No. E-999/CI-03-869, Order Paragraph 7.

concerns about the potential impact of the requirements contemplated by MLIG on smaller utilities.

C. CFS Eligibility and Percent Carbon-Free Determinations

1. Commenter Positions

Xcel restated its preferred methodology of considering the amount of net generation defined as carbon-free correlated to the annual CO_2 emissions of the unit. Further, Xcel supported providing RECs or AECs for the percent of generation (based on heat content) associated with carbon-free or EETS-eligible fuels.[275] Xcel acknowledged that the Commission will be discussing partial compliance further in Docket No. E-999/CI-24-352 and intends to continue to monitor those discussions.

Comments made by Health Professionals for a Healthy Climate (HPHC), Climate Generation, CURE, Minnesota Environmental Justice Table, Minnesota Interfaith Power and Light, MN350, and Sierra Club North Star Chapter (HPHC et. al.) argued against any decision to recognize biomass and waste incineration as carbon-free resources.[276] They argued that these technologies emit significant amounts of carbon and other pollutants, and therefore violate the plain language and intent of the law. The parties cited data showing that emissions from these sources are comparable to, or worse than, those of coal, and argued that granting these resources the ability to generate credits for CFS compliance undermines Minnesota's climate goals.

The Partnership on Waste and Energy submitted comments noting that the appropriate time and forum for decisions on eligibility should be in the LCA Docket.[277]

CEOs recommended the Commission explicitly state that RECs must be from carbon-free sources to be used for compliance with the CFS, and that no RECs from biomass or solid waste facilities may be used unless those facilities have been subject to a life-cycle analysis and have had their carbon-free status approved by the Commission.[278] **(Decision Option 37)** The Department agreed with CEOs' recommendation, but argued that the LCA Docket is the appropriate venue for the Commission to discuss and make such a determination.[279]

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[275] Xcel Initial at 6.

[276] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Health Professionals for a Healthy Climate (HPHC), Climate Generation, CURE, Minnesota Environmental Justice Table, Minnesota Interfaith Power and Light, MN350, and Sierra Club Initial Comments at 2 (January 29, 2025) (hereinafter "HPHC et. al. Initial").

[277] *In the Matter of an Investigation into Implementing Changes to the Renewable Energy Standard and the Newly Created Carbon-free Standard under Minn. Stat. § 216B.1691*, Docket No. E-999/CI-23-151, Partnership on Waste and Energy Reply Comments at 1 (March 19, 2025) (hereinafter "Partnership on W&E Reply").

[278] CEOs Supplemental at 12.

[279] Department Reply at 20-21.

2. Staff Analysis

Staff agrees with Xcel and the Partnership on Waste and Energy that the Commission has decided to discuss the topic of how much carbon to assign to a partially carbon-free unit in the LCA Docket and recommends that both Xcel and HPHC et. al. reiterate their positions in that docket, if appropriate.

Regarding the CEO's requested clarification in **Decision Option 37**, Staff agrees with the Department that the LCA Docket is likely the appropriate place to make a determination on this issue. Staff further notes that it may not be necessary to explicitly state that the carbon-free standard can only be met by carbon-free resources.

D. Other Pollutants

1. Commenter Positions

HPHC et. al. argued that co-pollutants produced by biomass and waste incineration – including nitrogen oxides, sulfur dioxide, volatile organic compounds, and fine particulate matter – are linked to respiratory and cardiovascular diseases, cancer, premature mortality, and developmental issues. They highlighted how these detrimental effects are concentrated in environmental justice communities where biomass and incineration facilities are disproportionately located.

These commenters urged the Commission to fully consider the health impacts of allowing the burning of biomass from any source. They recommended including these health externalities in utility planning and emissions tracking to avoid burdening overexposed communities.[280]

The Department responded to these comments and concluded that they fall outside of the scope of orders issued Minn. Stat. § 216B.1691. They noted that the statute directs the Commission to issue orders to establish criteria and standards used to measure utilities efforts to meet the various REO Standards and specified that in establishing these standards the Commission must allow for partial compliance while protecting against undesirable impacts on the reliability of the utility's system and customers. The Department claims that HPHC et. al.'s requests fall outside of these considerations and instead relate to issues typically handled by the MPCA.[281] LIUNA agreed with the Department's position.[282]

2. Staff Analysis

Staff has reviewed the record and agrees that this discussion is outside the scope of the CFS Docket, which is limited by the REO statute.

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[280] HPHC et. al. Initial at 2.

[281] Department Reply at 12.

[282] LIUNA Supplemental at 1.

DECISION OPTIONS

IX. Threshold Issues

REC (or Equivalent) Retirement to Substantiate Compliance

1. The Commission authorizes utilities to demonstrate compliance with the Carbon-Free Standard by retiring Renewable Energy Credits, Alternative Energy Credits, or equivalent Environmental Attribute Credits registered with the Midwest Renewable Energy Tracking System.

Support: CSG, CRS, CMPAS, CEOs, Department, EnergyTag, Great River Energy, LIUNA, M-RETS, Minnesota Power, Minnkota, MRES, OTP, Ramsey/Washington R&E, Xcel

2. The Commission authorizes utilities to propose alternative methods to demonstrate compliance with the Carbon-Free Standard for Commission approval.

Support: LIUNA, Minnesota Power, Minnkota, OTP
Opposed: CEOs, CRS, CSG, Department, M-RETS

Partially Carbon-Free Facilities

3. In demonstrating compliance with the Carbon-Free Standard, utilities shall apply the following methodology to partially carbon-free facilities:

A. EACs shall be issued equivalent to metered generation on a per MWh basis;

B. A single REC shall be issued for all generation that may be retired to demonstrate both EETS and CFS compliance;

C. A carbon-free allocator, which defines the percentage of CFS eligible generation, must be used for any generation facility that is partially CFS compliant;

D. For all generation made in a CFS partial compliant facility that is also eligible for the EETS, metered generation in A. shall be:

i. Multiplied by C to determine the whole number of RECs to issue that are fully eligible for both the EETS and the CFS;

ii. Multiplied by one minus C to determine the whole number of RECs to issue that are only eligible for the EETS;

E. For all generation made in a CFS partial compliant facility that is not eligible for the EETS, metered generation in A. shall be multiplied by C to determine the whole number of AECs to issue that are only eligible for the CFS; and

F. The methodology to determine the carbon-free allocation shall be decided in

Docket No. E-999/CI-24-352.

Support: Department, Staff

OR

4. Partially carbon-free facilities must be granted partial certificates or carbon-free credits; the Commission will work with M-RETS to develop these credits.

Support: CEOs

OR

5. All matters concerning partially compliant facilities will be discussed in the Life-Cycle Analysis Docket, Docket No. E-999/CI-24-352.

Support: CMPAS, Xcel

Net Market Purchases: Credit Tracking

6. To substantiate the carbon-free portion of net market purchases in CFS compliance, utilities must accompany net market purchases with RECs/AECs.

Support: CRS, CSG, Department, M-RETS
Opposed: Connexus, Great River Energy, LIUNA, MRES

OR

7. To substantiate the carbon-free portion of net market purchases in CFS compliance, utilities may provide a market fuel mix calculation.

Support: Connexus, Great River Energy, LIUNA, MRES
Opposed: CRS, CSG, Department, M-RETS

8. Net market purchases shall only be quantified for CFS compliance when the carbon-free share of the systemwide annual fuel mix or an applicable subregional fuel mix is necessary to demonstrate CFS compliance.

Support: Department

9. The Commission delegates authority to the Executive Secretary to issue a notice of final comment period in the Carbon-Free Standard Docket, Docket No. E-999/CI-23-151, once matters in the Life-Cycle Analysis Docket, Docket No. E-999/CI-24-352, have been resolved.

Support: CMPAS, Staff

OR

10. All matters concerning net market purchases will be discussed in the Life-Cycle Analysis Docket, Docket No. E-999/CI-24-352.

Support: CMPAS, Department

Reporting: Annual REO Reports

11. Beginning in 2026, each electric utility shall file a report on June 1st with its Renewable Energy Objectives compliance report in Docket No. E-999/PR-YR-12 that includes the following information detailing its efforts toward complying with Minnesota's Carbon-free Standard:

A. Annual Minnesota retail sales for the previous calendar year.

B. Annual net market purchases from the previous year.

C. Annual qualifying carbon-free generation procured or generated by the electric utility in the previous calendar year, including the total number of facilities registered in M-RETS to that utility and eligible Renewable Energy Credits (or other equivalent Energy Attribute Credits) generated in the past year from those facilities.

D. A list of facilities determined to be partially compliant with the CFS, including the name of the facility, the facility fuel type, and the percent of that facility's output determined to be carbon-free.

E. From 2026-2030, electric utilities must also report the following:

i. Estimated amount of carbon-free generation (expressed as capacity) a utility would require to obtain in 2030.

ii. Estimated carbon-free requirements to meet the CFS in 2030.

iii. A short summary of ongoing efforts to obtain carbon-free energy, including a brief summary of the anticipated resource mix for CFS compliance.

iv. Any considerations, such as those outlined in Minn. Stat. § 216B.1691, subd. 2b, that may create challenges with achieving compliance, and which under Minn. Stat. § 216B.1691, subd. 2h(f), may allow the Commission to modify or delay implementation.

Staff Proposed

AND

12. The Commission delegates authority to the Executive Secretary to work in conjunction with the Department of Commerce and utilities to update the Renewable Energy Objectives reporting template to incorporate the reporting requirements approved in this docket and modify them as necessary based on the results of the LCA Docket, Docket No. E-999/CI-24-352.

Staff Proposed

X. Additional Considerations

Hourly Matching for CFS Compliance

No current decision options.

Hourly Matching Workgroup

13. The Commission delegates authority to the Executive Secretary to convene a stakeholder workgroup that is tasked with the analysis, development, testing, and recommendation of best practices for the optimization of societal costs as they pertain to:

A. Hourly matching for CFS compliance;

B. Methodologies to implement hourly matching scenario requirements in integrated resource plans;

C. The integration of transmission constraints in integrated resource plans;

D. The integration of energy attribute certificates and allocation thereof in integrated resource plans;

E. Stochastic modeling of variable renewable generation into integrated resource plans; and

F. The co-optimization of transmission and generation resources.

Support: Department

Hourly Matching in IRP

14. In all integrated resource plans where the utility uses a capacity expansion model, the utility shall incorporate hourly matching constraints in the models to demonstrate CFS compliance.

Support: CEOs, Department, EnergyTag, Google
Opposed: Aligned Utilities, Great River Energy, MRES

OR

Staff Modified 14. In future resource plans, and to the extent practicable, IRP-filing utilities shall incorporate one or more contingencies that use an hourly matching construct to achieve the state's CFS. Utilities shall accompany this with a discussion of the potential costs, benefits, possibilities, and limitations of a potential future regulatory hourly matching requirement.

Staff Proposed

15. In future resource plans, IRP-filing utilities shall report hourly information concerning carbon-free versus non-carbon-free resources for each of the Commission's required regulatory/externality scenarios.

Staff Proposed

Hourly Data Reporting

16. All electric utilities shall report sales and purchases of EACs at the time interval required for CFS matching, or at the smallest time increment possible, with their REO annual reports.

Support: Department
Opposed: CMPAS

17. All electric utilities shall report their hourly Minnesota retail electric sales for the previous calendar year with their REO annual reports.

Support: Department
Opposed: CMPAS

18. With their annual REO reports, utilities shall include the following information:

a) The utility's projected reliance on RECs purchased without purchasing the associated energy (unbundled RECs) to comply with the CFS through 2040.

b) A discussion of the expected hourly timing of anticipated carbon-free generation (with bundled RECs) and unbundled REC purchases through 2040.

c) An estimate of what the utility's projected compliance with the CFS would be through 2040 if RECs could only be claimed if they were time-matched.

d) For filings verifying compliance with a previous year's CFS, an estimate of the utility's carbon-free percentage if the RECs it purchased and generated had to be time-matched with the utility's demand on an hourly basis.

e) a discussion of any barriers to acquiring the information listed above and efforts the utility has made to obtain or estimate it.

Support: CEOs
Opposed: Basin, Xcel

Hourly EAC Tracking and Certification

19. Public electric utilities shall investigate and implement systems to track and certify clean energy on an hourly basis. Within six months of this Order, each applicable utility shall file a report in this docket including a summary of their investigations and an implementation action plan and timeline.

Staff Interpretation of Google

Shelf Life of RECs

20. Effective January 1, 2030, the Commission amends Order Points 1 and 3 from its December 18, 2007 Order in Docket Nos. E-999/CI-04-1616 and E999/CI-03-869 and modifies order point 6 of the Commission's December 6, 2023 Order in Docket E-999/CI- 23-151 to remove "All renewable energy credits generated from such facilities will be eligible for use in the year of generation and for four years following the year of generation," and replace that language with "All renewable energy credits generated from such facilities will be eligible for use in the year of generation and for one year following the year of generation."

Support: Department
Opposed: Basin, CMPAS, Great River Energy, Xcel

OR

21. The Commission affirms that for purposes of Renewable Energy Objective compliance substantiation, Renewable Energy Credits and Alternative Energy Credits from carbon-free, non-renewable facilities will be eligible for use in the year of generation and for four years following the year of generation.

Support: CMPAS

Geographical Considerations

22. With their annual REO reports, utilities must provide the following information:

A) The electric utility's predicted and actual rates of compliance with the Minnesota CFS, based on the statutory formula below:

$$\frac{\text{"electricity generated from a carbon-free energy technology to provide the electric utility's retail customers in Minnesota"}}{\text{"the electric utility's total retail electric sales to retail customers in Minnesota"}}$$

The utility must precisely explain how the numerator and denominator were calculated, and it must demonstrate that it has only included in the numerator carbon-free electricity (and/or applicable RECs) generated or procured to provide to retail customers in Minnesota (and therefore, that it has excluded electricity that serves customers in other states, that supports net sales to regional markets, or that is sold to other parties that are not Minnesota retail customers).

B) the utility's predicted and actual percentage of carbon-free generation on a system-wide basis. If the percentage of carbon-free generation claimed under the Minnesota CFS calculation in item A above is different than the percentage of carbon-free generation on the utility's total system, the utility must identify and explain the difference.

C) the utility's predicted and actual estimated line losses, including the basis for the estimate and an explanation of how those line losses affect the calculation under item A above.

D) the utility's predicted and actual sales to parties other than retail customers in Minnesota, specifically identifying net annual sales to regional markets, sales to retail customers in other states, and any other sales to parties other than Minnesota retail customers. The explanation must state whether the utility has sold the RECs associated with any of these sales if they are of carbon-free power.

E) the utility's predicted and actual purchase of RECs or retention of RECs from generation provided to non-Minnesota retail customers or from excess sales to MISO or other regional markets, identifying which are bundled and which are unbundled. RECs attributable to electricity generated or procured by the utility must be listed as bundled RECs, and those purchased from other parties where the energy associated with the REC was not purchased must be listed as unbundled RECs.

F) the predicted and actual CO2 emissions associated with all electricity generated or procured to provide retail customers in Minnesota, including emissions associated with the excess power generated or procured to cover line losses.

Support: CEOs, Department (C only), MLIG (C and D only)
Opposed: Xcel

23. Only generation located within Minnesota or MISO North shall be CFS eligible**.**

Support: CSG
Opposed: Basin, CMPAS, Minnkota, MRES

OR

24. Utilities may use EACs from any location for EAC compliance, as long as those EACs meet all eligibility requirements for CFS.

Support: CMPAS

25. All procurements of physical assets, PPAs, and any other contract that involves EACs necessary to meet Minn. Stat. § 216B.1691 compliance requirements shall be subject to the following geographic preference reporting requirements at the time the procurement decision is proposed:

A. Procurements Within Minnesota:

1. The number of EACs expected to be procured each year.

B. Procurements in Counties or Municipal Divisions Bordering Minnesota:

1. The number of EACs expected to be procured each year.

2. The state and county or municipal division and country of procurement.

C. Procurements in the MISO territory of Non-Border Counties of North Dakota, South Dakota, Iowa, Wisconsin, and Manitoba:

1. The number of EACs expected to be procured each year.

2. The state and county or municipal division and country of procurement.

3. Explanation of any technical, cost, or other constraints that preclude a procurement under A. or B.

4. Explanation of any local benefits including jobs, tax revenue, other economic factors, air quality, and environmental justice considerations that will not be received by Minnesota ratepayers.

D. Procurements in all Other Locations:

1. The number of EACs expected to be procured each year.

2. The state and county or province of procurement.

3. Discounted cash flow that demonstrates why a procurement under A., B., or C. is financially harmful to Minnesota ratepayers.

4. Technical analysis of why there is insufficient transmission, siting, or unbundled EAC availability under A., B., or C.

5. Quantification of any local benefits including jobs, tax revenue, direct and indirect economic factors, air quality, and environmental justice considerations that will not be received by Minnesota ratepayers.

Support: Department

Line Losses

26. To comply with the CFS and EETS, utilities must factor line losses into their compliance measurements.

Support: Department
Opposed: Xcel

Clean Transition Tariff

No current decision options.

Net Market Purchases: Average Fuel Mix vs. Residual Mix Accounting

27. When calculating partial compliance credit for net market purchases, utilities must use a MISO subregional residual fuel mix. The Commission will work with M-RETs to establish a subregional residual mix that all utilities in a subregion may use in their calculations.

Support: CRS
Opposed: Connexus

OR

28. For unspecified net market purchases, an obligated entity's remaining CFS requirement

shall be calculated based upon an applicable subregional residual fuel mix at the utility-specific level.

Support: CSG
Opposed: Connexus

29. When calculating partial compliance credit for net market purchases, utilities participating in MISO must use the fuel mix of the MISO North subregion (Local Resource Zones 1-7).

Support: CEOs, Great River Energy, OTP, Xcel

Enhanced Auditing

30. The Commission requests that the Department perform enhanced auditing of utility REO reports. Pursuant to Minn. Stat. § 216B.62, subd. 8, the Commission requests that the Department seek authority from the Commissioner of Management and Budget to incur costs for specialized technical and professional investigative services to assist with auditing of all CFS reports for up to three years.

Support: CEOs, Department

31. The Department will make a filing within six months of this Order, proposing a process for enhanced audits. The Commission delegates authority to the Executive Secretary to set a procedural schedule for interested parties to comment upon the Department's proposal. Enhanced audits performed by the Department should follow an established process, with initial input by utilities.

Support: CMPAS

Request for Common Definitions

32. The Commission delegates authority to the Executive Secretary to issue a list of common definitions, open for notice of comment, to develop shared terminology. Terms on the list will include, but are not limited to: bundled EAC, unbundled EAC, specified purchase, unspecified purchase, specified resource.

Staff Interpretation of CMPAS

XI. Topics Outside the Scope of this Round/Docket

Contract Off-Ramps

33. RECs or AECs from existing contracts shall be eligible for CFS compliance beyond 2030.

Support: CMPAS

Cost and Reliability Reporting

34. Pursuant to Minn. Stat. § 216B.1691, subd. 2e, the Commission requires all electric utilities to file:

A. A reference case scenario, detailing the least cost plan, from a ratepayer impact perspective, for meeting the CFS by 2040 and 2050; and

B. A reference case scenario, detailing the least cost plan, from a ratepayer impact perspective, to partially meet the CFS by 2040 and 2050.

Support: MLIG

35. With their annual REO reports, utilities shall provide information about how compliance with the EETS, SES, and CFS impacts system reliability

Support: MLIG

CFS Eligibility and Percent Carbon-Free Determinations

36. RECs, AECs, or equivalent EACs must be from carbon-free sources to be used for compliance with the CFS, and no RECs from biomass or solid waste facilities may be used unless those facilities have been subject to a life-cycle analysis and have had their carbon-free status approved by the Commission.

Support: CEOs