GREAT RIVER ENERGY™

12300 Elm Creek Boulevard
Maple Grove, Minnesota 55369-4718
763-445-5000
greatriverenergy.com

March 19, 2025

- Via Electronic Filing -

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: Great River Energy Reply Comments
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. E999/CI-23-151

Dear Mr. Seuffert:

Pursuant to the Minnesota Public Utilities Commission's ("Commission") February 4, 2025, Notice of Extended Reply Comment Period ("Notice"), Great River Energy ("GRE") submits the following Reply Comments on questions related to implementation of, and compliance with, the new carbon free standard ("CFS") set forth in Minn. Stat. § 216B.1691.

In these Reply Comments, GRE focuses its discussion on the key points raised by the Minnesota Department of Commerce (Department) in its January 29, 2025, Comments. Although the Department makes numerous valid points regarding the implementation of the CFS, it also creates substantial complexity, where there is none today in the law. GRE plans to meet its CFS mandated targets of 60 percent by 2030, 90 percent by 2035, and 100 percent by 2040. However, the manner in which utilities do so is important. As written, and negotiated, the CFS creates one of the most aggressive state decarbonization laws in the country, and the Department's comments and recommendations to the Commission hold the potential to increase costs where there is no explicit requirement to do so, for minimal incremental gains that are not present in state law. These Reply Comments explicitly address a number of these recommendations, including:

- Hourly Matching of Generation to MN Net Retail Sales
- Carbon-Free Percentage of Net Market Purchases
- Reporting and Modeling Hourly Matching
- Impact of Eliminating Annual renewable energy certificate (REC)/ alternative energy certificate (AEC) Banking
- Dispatching Capacity Resources out of MISO's Merit Order

The Department begins its comments on page 1 of its filing with a question posed to the Commission:

> *The current proceeding is fundamentally about what carbon-free electricity actually means in practice. The Commission must decide if carbon-free means clean, firm power that attempts to match real-time loads where they occur, or if carbon-free means 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.*

In practice, the Legislature has clearly indicated how a utility is to comply with the CFS via eligible carbon free energy generation or procurement according to certain percentages of total retail electric sales by dates certain in Minn. Stat. § 216B.1691. As indicated in the jointly filed comments of the Aligned Utilities in this proceeding, those sales are defined in statute as annual sales, not hourly in Minn. Stat. § 216B.1691 Subd. 1f:

> *"Total retail electric sales" means the kilowatt-hours of electricity sold <u>in a year</u> [emphasis added] by an electric utility to retail customers of the electric utility or to a distribution utility for distribution to the retail customers of the distribution utility.*

Nothing in Minn. Stat. § 216B.1691 references or considers matching in real-time. Although this may be the preference of the Department, current law does require or even mention the concept of hourly compliance. If the Commission were to decide to order an hourly matching-based compliance standard for the CFS, it would be unsupported by both the spirit and language of Minn. Stat. § 216B.1691 and outside the construct of the CFS as contemplated and passed into law by the Legislature.

There are not multiple future options for compliance with the CFS, structurally. As currently written, GRE finds Minn. Stat. § 216B.1691 to be clear in its directives to both the Commission and the utilities subject to the CFS. GRE was a key participant in the negotiations and discussions surrounding the formation of this groundbreaking decarbonization policy, and the development of this record, and the creation of a grounding basis of facts from which the Commission can base decisions is important in helping the utilities subject to the standard to create cost-effective, reliable, and sustainable strategies to compliance. The Department's recommendation to the Commission would require utilities to revisit the very structure of the standard itself in Minn. Stat. § 216B.1691 Subd. 2g.

Compliance with the CFS will be challenging enough without the added complexity and costs that would result from adoption of the Department's recommendations, forcing utilities to proactively plan and integrate decisions into their Integrated Resource Plans (IRPs) to ensure the standards are met. As utilities incorporate the CFS into their IRP optimization strategies, they do so with an understanding that the negotiated requirements that are memorialized in statute today are the clear directives around which they must plan. The Department and other intervenors are asking the Commission to move the goalposts and approve a new standard outside of the legislative process that goes well beyond the current CFS as negotiated, written, and signed into law, increasing the complexity, scope, and costs that will need to be borne by Minnesotans.

A) The Nature and Intent of Integrated Resource Planning

At its core, the IRP process is the foundation of a utility's strategy to plan, procure, and deliver the optimal mix of energy resources - determining what to build, when to build it, and at what scale - to ensure a stable and sufficient energy supply. This process requires balancing reliability, affordability, regulatory obligations, and societal impacts to create a resilient and sustainable energy future.

The IRP process is both a science and an art, particularly when utilizing capacity-expansion and production-cost modeling to determine future system needs. The science comes from the use of complex modeling, statistical methods, and historical data to forecast how the grid will function under future scenarios. The art, however, lies in the interpretation of these models, the assumptions made about future conditions, and the expert judgment required to balance uncertainty with practicality. Ensuring the certainty of the conditions around which utilities optimize their models is one of, if not the most important part of the process. Without accurate, and known parameters, the models cannot provide an accurate recommendation to the regulatory entities, whether a Commission to an investor-owned utility, or a board of directors of an electric cooperative.

Today, there is a clear framework and standard present in Minn. Stat. § 216B.1691 surrounding the compliance with applicable standards that utilities must demonstrate to the Commission during the IRP process.

> *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 <u>*equivalent to at least the following standard percentages of the electric utility's total retail electric sales [emphasis added]*</u> *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.

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* <u>*equivalent to at least the following standard percentages of the electric utility's total retail electric sales*</u> *[emphasis added] 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.

As outlined below, the Department, and other intervenors' recommendation that the Commission create a structurally new standard than was contemplated and negotiated during the formation of the CFS creates numerous inefficiencies and cost increases as utilities plan and demonstrate compliance.

B) Hourly Matching of Generation to MN Net Retail Sales

With respect to comments in the record that advocate for hourly matching of generation and total electric retail sales, GRE's position is stated in the Joint Reply Comments of the Aligned Utilities submitted to this docket on March 19, 2025. In addition, GRE has included supporting analysis prepared by Dr. Kathleen Spees and Dr. Long Lamb from The Brattle Group (Brattle) in Appendix A of this filing that provides empirical evidence supporting the Aligned Utilities' recommendation that the Commission reject the call to adopt a new hourly matching construct for the CFS as requested by some intervenors in this proceeding.

Brattle is a highly respected economic consulting firm that specializes in energy, finance, and regulatory economics. They provide third-party expert analysis, policy recommendations, and strategic consulting to utilities, regulators, policymakers, and private sector clients. GRE engaged Brattle to analyze the economic implications and challenges of hourly matching as a carbon-free energy procurement strategy. Their analysis includes a review of existing research comparing hourly matching to annual matching, as well as an estimate of the potential costs and effectiveness of different procurement strategies. Additionally, the report examines developments in greenhouse gas (GHG) emissions accounting and tracking in other jurisdictions, providing insights that may help inform the Commission and Minnesota policymakers.

On page 6 of its Comments, the Department states:

> *Minn. Stat. § 216B.1691 subd. 2g sets a clear standard to match percentages of an electric utility's "total retail electric sales to retail customers in Minnesota" with carbon-free electricity, however the statute is silent on electric generation from CFS-ineligible generation sources such as coal and natural gas-fired generation, or the carbon-emitting fraction of energy generation from partially compliant sources.*

This phrase "CFS-ineligible generation" is continually used throughout the Department's comments. To be clear, the phrase "CFS-ineligible generation" does not appear in any statute or administrative rules and appears to characterize the CFS as generation-based. The CFS is a load-based standard, measured as a percentage of total electric retail sales. All cost-effective generation may continue to operate and support grid reliability if the utility is meeting the CFS standards relative to total electric retail sales in each compliance year. This characterization and explicit reference to the CFS somehow governing generation resources is not considered in statute which is well understood to be a load-based compliance construct, like the renewable energy standard (RES). The CFS was carefully crafted and directed at total electric retail sales in a manner that helps insulate it from potential challenges that Minnesota is engaging in the extra-territorial regulation of generation resources outside of the state.

C) Carbon-Free Percentage of Net Market Purchases

GRE maintains that the Commission's directive in in Minn. Stat. § 216B.1691, Subd. 2d (ii) is clear and unambiguous:

> *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 [emphasis added] calculate based on the regional transmission organization's systemwide annual fuel mix* ***or*** *[emphasis added] an applicable subregional fuel mix.*

In its current form, the Statute provides only two options for determining the carbon-free percentage of net market purchases: 1) a systemwide fuel mix, or 2) an applicable subregional fuel mix.

GRE agrees with the comments filed within this docket advocating for the use of a Midcontinent Independent System Operator (MISO) North subregional fuel mix – specifically, Local Resource Zone (LRZ1) highlighted in Figure 1 below.

LRZ 1 includes the majority of Minnesota, and this region of MISO North most accurately reflects the mix of resources serving load in Minnesota. In determining the historical and projected annual fuel mix, GRE recommends the Commission direct utilities to utilize the MISO Grid Emissions Map application powered by Singularity[1] as illustrated in Figure 1 below.

[1] https://miso.singularity.energy/

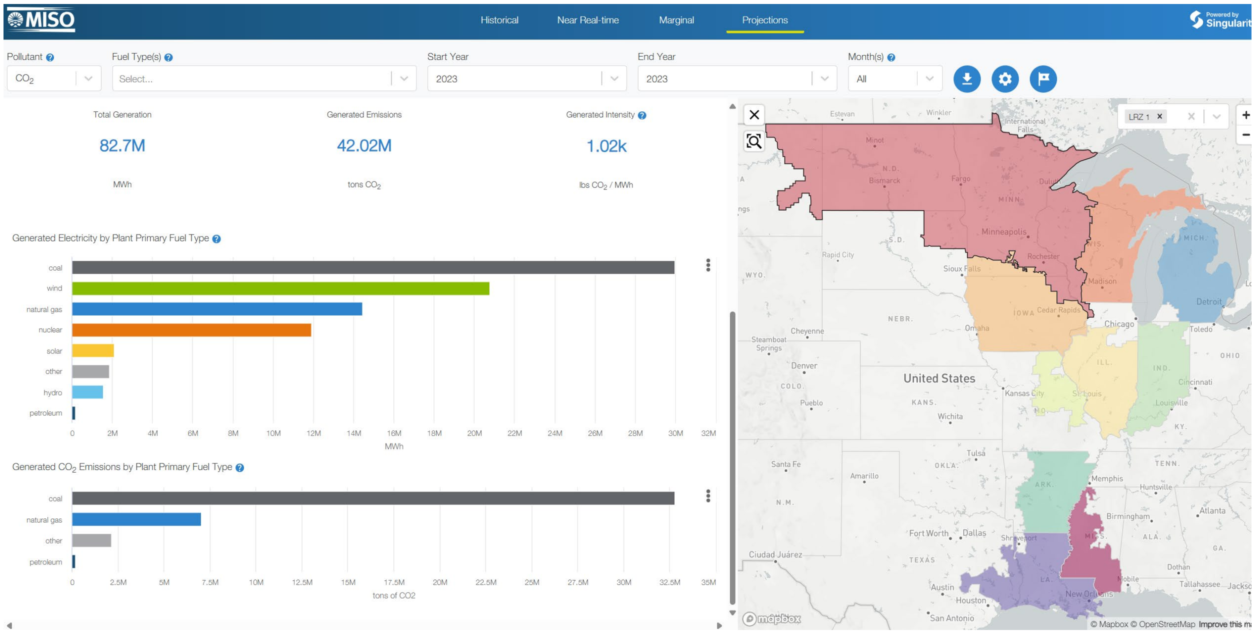

Figure 1 LRZ 1 highlighted within the MISO Grid Emissions Map application powered by Singularity

The MISO Grid Emissions Map application is a tool developed in 2022 to provide insights into grid operations. It includes the historical, real-time, and projected carbon intensity and resource mix of MISO electricity generation. GRE contends that, although no data source or application will be 100 percent accurate, this application will provide increasingly accurate data as it evolves. The tool leverages historical emissions data from the United States Energy Information Administration (EIA) and the United States Environmental Protection Agency (EPA), near real-time/marginal emissions data from MISO's website, and projected emissions data informed by member-provided resource plans combined with MISO-modeled future capacity.[2]

Employing this tool will ensure all utilities are utilizing consistent and high-quality data, provided directly from MISO. This data will allow the Commission to interpret the carbon intensity of net market purchases in Minn. Stat. § 216B.1691, Subd. 2d (ii) and its contribution to utilities' overall compliance demonstrations for the CFS.

[2] https://help.misoenergy.org/knowledgebase

In its comments, MRET-S makes the following statement regarding the treatment of net market purchases:

> ***III. How should net market purchases be counted towards CFS compliance?***
>
> *M-RETS asserts that the Commission should require regulated entities claiming renewable or clean electricity consumption to use RECs, AECs, or the Commission's preferred energy attribute certificate to validate their claims, due to the double counting raised in Section II.*

If MRET-S is stating in the above passage that utilities be required to retire RECs / AECs for all net market purchases, then GRE strongly disagrees with this assertion from MRET-S that the Commission issue orders that go beyond the law as written in Minn. Stat. § 216B.1691, Subd. 2d (ii).

The language clearly states that the Commission shall issue necessary orders detailing criteria and standards to measure compliance with Minn. Stat. § 216B.1691, Subd. 2g and requires the Commission to allow for partial compliance with the CFS for the percentage of annual net purchases from a regional transmission organization (in this case, MISO) that are carbon-free, as calculated by the Commission. GRE's position is clear in the above section, that the MISO Grid Emissions Map is the most transparent and indicative tool for compliance with Minn. Stat. § 216B.1691, Subd. 2d (ii).

The language in the law is clear, and if MRET-S is indeed taking a policy position that asserts the Commission must order a more stringent standard that contradicts current statute, it would effectively disallow the intent of the CFS legislation regarding partial compliance for net interaction with the MISO market unless RECs / AECs are retired for all net purchases, not just those that are carbon-free. Adoption of MRET-S' apparent position would increase costs for Minnesotans as utilities would need to increase either generation or purchase of RECs / AECs for all net purchases. Such a result runs counter to the plain language and intent of the CFS as promulgated by the Legislature.

D) Reporting and Modeling Hourly Matching

Unless the Commission orders an hourly carbon-free matching requirement, GRE contends that mandating hourly reporting and modeling during a CFS preparedness period or the CFS compliance period is unduly burdensome. It imposes compliance obligations far beyond statutory requirements without providing meaningful benefit.

The Department's comments state on page 8:

> *Currently, the electric industry is moving towards an hourly-matching construct, which strikes a balance between data resolution and the feasibility of implementation.*[3]

GRE does not believe there is substantial support for this conclusion, nor is any provided in the Department's Comments.[4] Although there is some interest in hourly matching from private companies and industry, both domestic and abroad, there is a vast difference between a private entities energy policy directives, and those that are implemented via public policy and regulatory bodies on public and non-public utilities, the costs of which are ultimately borne by the consumer. Privately and publicly held companies may choose to pursue any energy policy directives they see fit, but those decisions do not dictate the direction an entire industry as a whole is moving, simply the decisions of those companies specifically. In Minnesota, the passage of the CFS represents one of the most aggressive standards in the United States, and planning to meet these requirements is a challenging task already. If the Legislature deems it appropriate to revisit the CFS and explicitly define the current goal to an hourly goal, the utilities will of course comply with the law. However, implementing a more aggressive standard than that passed into law will make an already difficult task even more complex.

The Departments comments on page 8 go on to say:

> *Notably, Minn. Stat. § 216B.1691, subd. 2d(a), provides the Commission with the authority to issue orders "detailing the criteria and standards used to [...] measure an electric utility's efforts to meet" the CFS. A requirement to use hourly matching is consistent with this grant of statutory authority, and, as explained below, would lead to more accurate data and is more likely to achieve the ultimate goal of shifting energy generation to carbon-free technology.*

The language cited by the Department claims that the Commission has the authority to supersede the legislature in formation of a much more aggressive and onerous standard than that negotiated and signed into law during the session. GRE contends that this language instead was intended to

[3] The Comments of the Minnesota Department of Commerce at Pg. 8, Section B.1.2.1.
[4] The Department does not provide citations, references, or context for this statement in its Comments.

allow the Commission to detail the criteria and standards used to measure efforts to meet the annual CFS as it is written in Minn. Stat. § 216B.1691. This standard was implemented to make Minnesota one of the leaders in the clean energy space, and the recommendation by the Department for the Commission to go even further is unfounded and would not fundamentally improve the decarbonization pathway of Minnesota as illustrated by the Brattle comments in Attachment A to this filing. The outcome from the Department's recommendation would likely lead to greater costs borne by Minnesotans across the state. GRE is greatly concerned about the impacts to its member-owners, and all Minnesotans, if the incremental costs of hourly compliance were to be recovered in electricity rates.

The Commission will, as always, provide leadership and direction to the utilities in how to measure and demonstrate compliance in a fair and balanced fashion, but the language cited in Minn. Stat. § 216B.1691 Subd. 2d(a) is not intended to allow for an end-around the legislative process in enacting fundamentally new, and more onerous standards.

GRE does not support the requirement of hourly matching in IRP modeling practices. Current methods of IRP modeling already provide insight into carbon-intense vs carbon-free generation in a utility's preferred plan. The annual generation mix for each scenario can provide an indication of how a utility will meet the CFS. On an annual basis, utilities can demonstrate what percent of the generation is expected to come from carbon-free resources.

In an hourly matching regime, a utility would have to purchase a time-stamped REC or AEC in hours when a carbon-intense resource dispatches, increasing the total portfolio cost in that hour of operation. A notable difference in Minnesota, is that current law and administrative rules already provide utilities with discrete values as price signals for regulatory cost scenarios via the future regulatory cost of carbon and the externality values, both of which are imputed in the model. The future cost of carbon regulation is included in the hourly dispatch of unit operations, providing a price signal and an implicit penalty to hourly operation of a carbon intensive resource already. The externality values additionally provide another cost of these thermal units, imputing an ex-post cost adder to scenarios that include fossil fuels generation and emissions.

Going further, and including an hourly dispatch constraint in the modeling, attempting to forecast the dynamic price of hourly RECs/AECs during each of the 8,760 hours over the 15-year IRP planning horizon is particularly challenging in practice and not an effective method to realizing incremental decarbonization beyond the existing requirements in both modeling methodology, and CFS / RES compliance.

Should hourly matching in IRP modeling be required, GRE is concerned about the accuracy of an hourly REC/AEC forecast without an existing hourly REC/AEC market on which to base forecast projections. An inaccurate hourly REC/AEC forecast will result in severe uncertainty in model results. Hourly carbon matching requires a near-perfect understanding of an unknown future resource mix, where assumptions about renewable generation, energy storage, and backup dispatchable resources must be made hour-by-hour, years in advance. GRE and utilities use the best forecasts and market information available to build inputs for modeling optimization. Including inherently uncertain hourly AEC / REC prices would compound uncertainty, likely leading to a flawed foundation for decision-making. GRE is also concerned about the feasibility and additional complexity of modeling an hourly AEC/REC market in EnCompass. Should the Commission desire to require hourly matching in IRP modeling, these topics should be discussed with stakeholders, including EnCompass software developer Yes Energy, before a requirement is put in place. The developers of these modeling software platforms can provide valuable insight as to the capabilities, limitations, and value added prior to ordering utilities to comply with new modeling requirements.

Lastly, the Department suggests that modeling hourly matching will:

> *ensure that electric utilities are not overly dependent on EAC markets and any market instability that may increase the financial burden imposed upon ratepayers.*[5]

The Department does not, however, provide suggested guidance of what qualifies as 'overly dependent.' More importantly, Minn. Stat. § 216B.1691, Subd. 4 allows utilities to meet the CFS with REC purchases and does not limit the number of REC purchases:

> *Subd. 4.***Renewable energy credits***. (a) To facilitate compliance with this section, the commission, by rule or order, shall establish by January 1, 2008, a program for tradable renewable energy credits for electricity generated by eligible energy technology. The credits must represent energy produced by an eligible energy technology, as defined in subdivision 1. Each kilowatt-hour of renewable energy credits must be treated the same as a kilowatt-hour of eligible energy technology generated or procured by an electric utility if it is produced by an eligible energy technology. <u>The program must permit a credit to 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 subdivision 2a or the solar energy standard obligation under subdivision 2f, if the credit meets the requirements of each subdivision.</u> [emphasis added] The 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. The commission must*

[5] The Comments of the Minnesota Department of Commerce at Pg. 12, Section B.1.2.3.

> *determine the period in which the credits may be used for purposes of the program.*
>
> *(b) In lieu of generating or procuring energy directly to satisfy a standard obligation under subdivision 2a, 2f, or 2g, an electric utility may utilize renewable energy credits allowed under the program to satisfy the standard [emphasis added].*

Additionally, as the Department is concerned with potential future financial burden of REC/AEC purchases, GRE is concerned with the financial burden on Minnesotans as a result of hourly matching, as stated previously.

An hourly matching construct will be extremely challenging to accurately model 15 years into the future given the lack of an existing market on which to base forecast projections. While modeling hourly matching may seem like a logical progression to mandate for MN IRP development and compliance reporting, the reality is that it is fraught with uncertainty and may very well result in negative unintended consequences with no incremental benefit.

E) Impact of Eliminating Annual REC/AEC Banking

If the Commission eliminates the ability for utilities to bank RECs/AECs beyond the current year of generation, it could have significant consequences for utility compliance with both the Minnesota RES and the CFS. For almost two decades, utilities have relied on a year-of-generation plus four-year REC banking construct to strategically manage RECs by balancing years and periods of high renewable generation with future compliance obligations. 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. This cost to consumers in the loss of existing assets and value and the future cost of lost flexibility could be significant. This is not to mention the market impacts of the forced liquidation of existing assets, and the loss of market power by utilities attempting to divest currently held RECs, which the market and counterparties would understand to be worthless in the future to the utilities, who would lose nearly all negotiating position.

F) Dispatching Capacity Resources out of MISO's Merit Order

In its Comments, the Department states:[6]

> *Nothing in the CFS precludes a utility from maintaining or building additional CFS-ineligible generation, for example, in order to meet MISO capacity requirements. Such resources will be dispatched according to the MISO merit order, which penalizes higher-variable cost resources such as future*

[6] The Comments of the Minnesota Department of Commerce at Pg. 6, Section B.1.1.

> *carbon-free hydrogen combustion turbines, for example. Even when all Minnesota utilities achieve 100% carbon-free electricity, all generation, including CFS-ineligible generation will be dispatched by MISO to meet grid capacity needs. If sufficient carbon-free capacity does not exist at any one time, and as discussed above, there is no guarantee that carbon-free capacity will be dispatched by MISO to meet of all Minnesota's capacity needs. Instead, the likely outcome is that if utilities do not possess sufficient carbon-free capacity, or if the carbon-free capacity is too expensive to routinely dispatch in the MISO merit order, MISO will dispatch lower cost CFS-ineligible resources external to utility-owned or -operated resources to meet Minnesota's capacity needs. The Department notes that, in the MISO dispatch process utilities can require MISO dispatch to occur out of economic merit order. This anomaly currently happens for some coal plants, for example.*

Once more, the Department refers to "CFS-ineligible generation", a phrase with no basis for regulatory decision making or action in current state law. Furthermore, while it is true that some utilities with baseload resources, such as coal, will require MISO to continually dispatch the resource at a minimum generation level, this is *not* the case with intermittent dispatchable resources such as a natural gas combustion turbine (CT).

In MISO operations, a baseload resource determines its minimum must-offer requirement based on a cost/risk/benefit analysis. If a baseload resource determines the cost and risk associated with shutting down and restarting their resource - including the unknown of when the resource will be re-dispatched and how many cycles the resource may incur - the baseload resource may self-schedule at a minimum generation level in MISO's Day-ahead auction. MISO will still dispatch the resource up to its maximum energy generation level based on real-time marginal LMPs and the incremental operating cost of the resource. The result is that MISO benefits from the baseload characteristics of the resource while operating at its minimum generation level even though the utility operating the resource is losing money during periods of high renewable generation and corresponding lower LMPs. The same is not true with intermittent dispatchable resources, such as a CT. They are engineered to cycle quickly and are fully compensated for each dispatch.

The Department appears to imply that if the cost of an hourly REC/AEC becomes prohibitively expensive during a time of low renewable generation resulting in a need for dispatchable capacity, carbon-free capacity resources - such as a hydrogen combustion turbine (HCT) - may become the preferable option in MISO's dispatch decision. This example is true, but it further illustrates how an hourly matching construct would increase costs for Minnesota ratepayers. A utility may be compelled to artificially lower its HCT offer in the MISO market if the cost to operate the HCT is less than the cost to operate a CT which requires a corresponding hourly REC/AEC. As a result, both offer strategies will ensure the unit operates uneconomically and both will negatively impact ratepayers.

G) Conclusion

GRE is fully committed to achieving the ambitious requirements currently in state law regarding the CFS.

If the utilities are held to a higher standard both in terms of complexity and cost than what is in law today, as the Department requests the Commission to order, the costs would ultimately be borne by GRE's member-owners, and by Minnesotans broadly served by other utilities subject to the standard. If the Commission were instead not to support the assertion of the Department that it requires hourly matching compliance and modeling for the CFS, the Commission would be doing as Minn. Stat. § 216B.1691 Subd. 2d intended in issuing orders detailing how to measure progress toward, and determine compliance with the law as written while exercising leadership in providing direction and support to the utilities subject to the CFS as it is achieved in practice.

Respectfully Submitted.

GREAT RIVER ENERGY

/s/ Zac Ruzycki

Director, Resource Planning
763-445-6116
zruzycki@grenergy.com

Cc: Service List