PUBLIC DOCUMENT
TRADE SECRET DATA REDACTED

STATE OF MINNESOTA
PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie Sieben	Commissioner
John Tuma	Commissioner

In the Matter of Great River Energy's 2018-2032 Integrated Resource Plan

Docket No. ET2/RP-17-286

CLEAN ENERGY ORGANIZATIONS' INITIAL COMMENTS ON GREAT RIVER ENERGY'S 2018-2032 INTEGRATED RESOURCE PLAN

TABLE OF CONTENTS

I. INTRODUCTION

Pursuant to the Commission's May 1, 2017 Notice of Comment Period and August 31, 2017 Notice of Extension/Variance, Minnesota Center for Environmental Advocacy respectfully submits these initial comments on Great River Energy's 2018-2032 Integrated Resource Plan ("GRE's 2018 IRP") on behalf of itself, Fresh Energy, Wind on the Wires, and Sierra Club (collectively, "Clean Energy Organizations" or "CEOs").

Consistent with Commission rules, our review evaluated GRE's 2018 IRP and its resource options on their ability to:[1]

- *maintain or improve the adequacy and reliability of utility service*;

  It appears to us that all plans evaluated would maintain adequate and reliable utility service. None of the plans GRE evaluated in System Optimizer appear to fail to satisfy resource adequacy requirements.

- *keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;*

  As addressed in Section IV, GRE is largely focused on rates and not bills. Even its own EE analysis, while flawed, shows that bills can be reduced through additional energy efficiency savings. On top of that, GRE has not considered the value of energy efficiency under multiple scenarios as required by the Commission in its order on GRE's last IRP.

- *minimize adverse socioeconomic effects and adverse effects upon the environment;*

  GRE's own modeling shows that under those scenarios including the Commission's established externality and regulatory values in place at the time GRE's IRP was prepared that early retirement of the Coal Creek units is preferable under most scenarios. Moreover, early retirement of Coal Creek could potentially be preferable as early as 2020, except that GRE's 2020 retirement analysis is irredeemably flawed.

- *enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and*

  GRE's plans and its resource options largely ignore the very financial, social, and technology factors affecting its operations. GRE offers no realistic assessment of energy

[1] Minn. R. 7843.0500, subp. 3.

efficiency, ignores available evidence indicating that load will continue to be flat to declining and does not realistically assess or model the future of Coal Creek. GRE's IRP is largely business as usual and as such cannot possibly enhance the utility's ability to respond to the financial, social, and technological factors affecting its operations.

- *limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.*

  As a cooperative, GRE is uniquely positioned to think creatively about how to respond to these factors outside of its control and to put these ideas into action, but instead it put together a business-as-usual plan. GRE might tout its grid modernization work or its electric vehicle program, but as discussed in Section V, electrifying new loads does not provide any environmental benefit under GRE's preferred plan resource mix.

In addition, our review revealed multiple instances in which GRE has failed to meet the spirit, let alone the letter of the Commission's order points from its last IRP. For all these reasons, we ask the Commission to reject GRE's 2018 – 2032 IRP.

II. COAL CREEK IS NOT ECONOMIC AND SHOULD BE RETIRED.

A. Coal Creek "Flexible Operations" Merely Make Coal Creek Operation Similar To Other Coal Plants.

In this IRP, GRE has touted its implementation of "flexible operations" at Coal Creek, but adding flexibility does not resolve the station's precarious economics. While we do not dispute that achieving this operational goal took an investment of capital and engineering, the end result is to move Coal Creek closer to how most coal units are operated, indeed to how Coal Creek used to operate.[2] As a MISO participant, GRE can choose to offer its coal units to MISO on a must run or economic basis. Prior to this IRP, GRE offered Coal Creek as must run, meaning that it specified the level of output not MISO. It can now offer the unit on an economic basis subject to minimum loading levels, but that is simply how most coal units are already offered in MISO.

[2] Matyi, Bob, *ND coal plant returns to its 'cycling' past.* S&P Global Platts, (Dec. 28, 2016).

We have received conflicting information from GRE about when Coal Creek commenced "flexible operations," but it appears that this switch has had little impact on the amount of energy produced by the units. Figures 1 and 2 show the net generation produced at the plant over two 12 month periods: July 2016 – June 2017 and July 2015 – June 2016.[3]

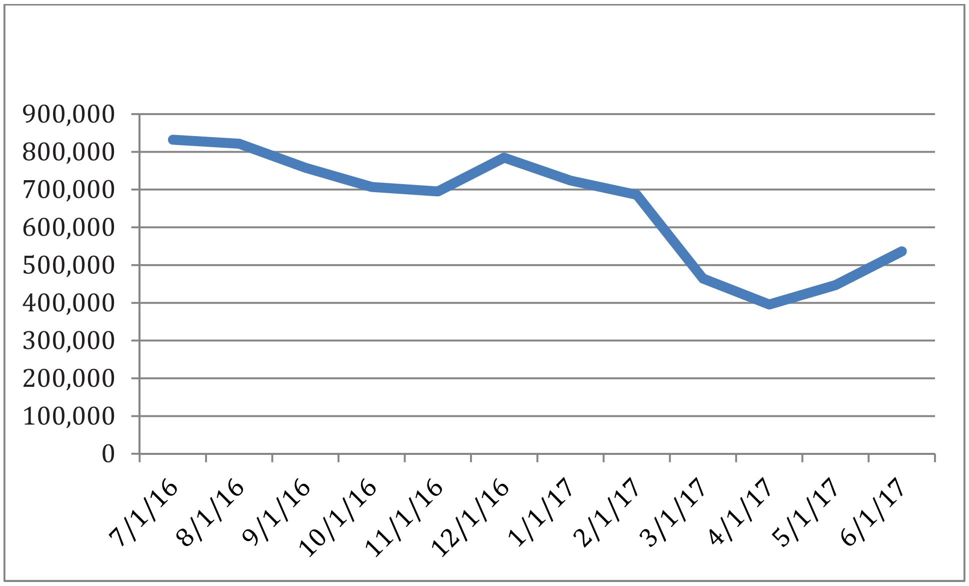


Figure 1. Net Generation from Coal Creek, July 2016 – June 2017

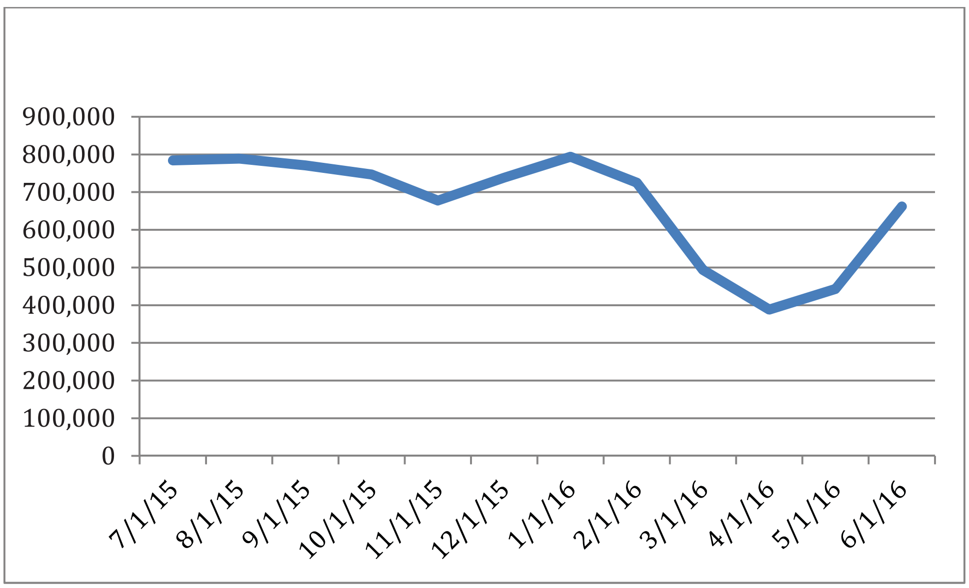


Figure 2. Net Generation from Coal Creek, July 2015 – June 2016

[3] These data were pulled from GRE's U.S. Energy Information Administration (EIA) Form 923.

Both figures clearly show a similar trend of generation, and over the two 12-month periods, there is a difference in capacity factor of just 1 percent. We asked GRE to provide us with its "typical" offers for the Coal Creek plant in an effort to see if the offers being made to MISO would explain why flexible operations and the switch to economic dispatch have had so little influence on net generation.[4] However, the information we received in response shed no light on this question.[5] Our discussions on these points with GRE staff did not clear up when Coal Creek was switched from must run to economic status, nor what costs its MISO offers are based upon. We invite GRE to clarify this issue in its reply. In particular, it would be helpful for GRE to clarify whether the tax benefits it receives from DryFining are included in these offers or not.

In short, the flexible operations instituted by GRE do not seem to have changed much at Coal Creek and, as discussed below, have not made it economic to run.

B. Rising Fuel Costs Put Coal Creek At Risk Of Losing Millions Of Dollars.

As CEOs have discussed in comments on at least one prior GRE IRP, the cost of coal at Coal Creek has been increasing and is expected to continue to increase simply because the coal seam from which Coal Creek's coal is mined is "getting deeper and farther from the plant."[6]

This fact is also reflected in data reported by GRE to the Energy Information Administration (EIA), which shows a generally increasing trend in the cost of coal supplied to Coal Creek.

---

[4] Clean Energy Organizations' Information Request No. 27c to GRE (July 21, 2017).
[5] Great River Energy's Response to CEO IR No. 27c (July 31, 2017) (refusal to answer); Great River Energy's Supplemental Response to CEO IR No. 27c (August 25, 2017) (Trade Secret Response).
[6] Comments of Izaak Walton League – Midwest Office, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy, 9 (March 18, 2013) Docket No. ET2/RP-12-1114.

Table 1. GRE's Cost of Delivered Coal, 2010 – May 2017

Year	Delivered Coal Cost (per ton)	Year-on-Year Increase
2010	$17.90	--
2011	$20.08	12%
2012	$21.40	7%
2013	$22.77	6%
2014	$22.41	-2%
2015	$23.33	4%
2016	$23.47	1%
Thru May 2017	$25.61	9%

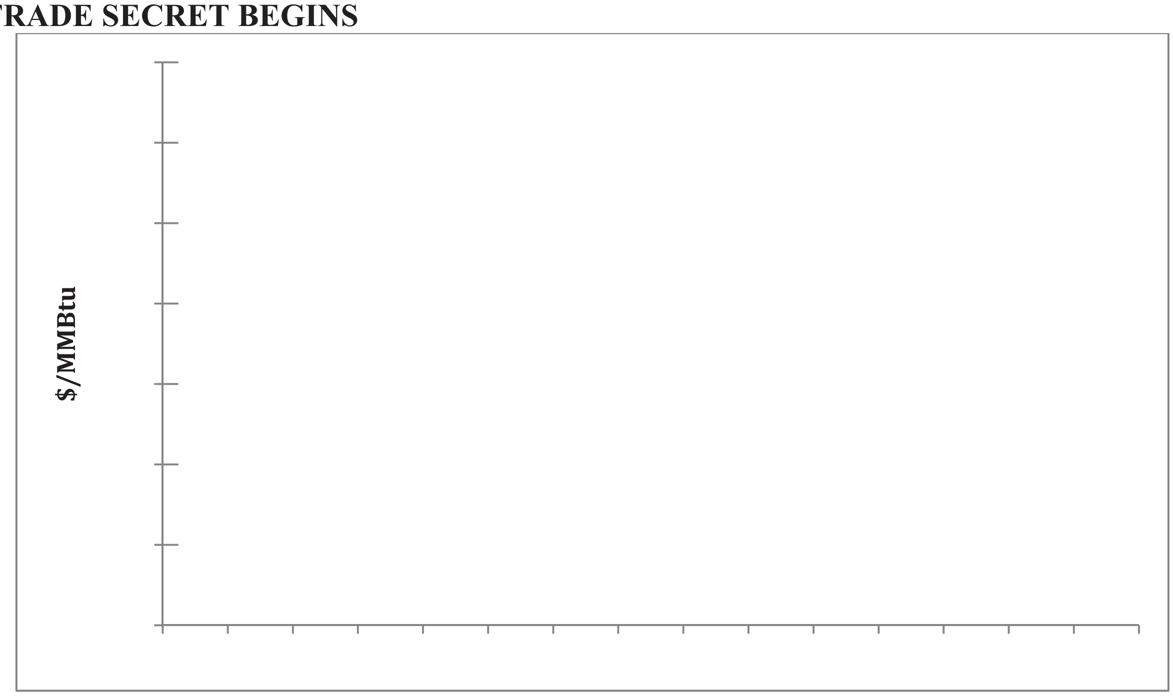
GRE's fuel price projections, as taken from System Optimizer also show a mostly

[TRADE SECRET BEGINS

TRADE

SECRET ENDS]; GRE never explains the rationale.

[TRADE SECRET BEGINS



TRADE SECRET ENDS]

Figure 3. GRE Forecasted Coal Costs at Coal Creek[7]

[7] Great River Energy's Response to CEO IR 1 (May 26, 2017).

What stands out the most from this graph, however, is the **[TRADE SECRET BEGINS**

TRADE SECRET ENDS].

As GRE explained in a discovery response to CEOs, "GRE currently receives financial benefits relating to development of its DryFining technology. These benefits are derived from Internal Revenue Code Section 45 and are scheduled to sunset in 2020."[8] The sunsetting of these benefits is very likely to make running the Coal Creek units uneconomic in the MISO market.

Based on communication with GRE staff, we understand that these IRS benefits are not currently reflected in fuel costs reported to EIA. This means that fuel costs reported to EIA speak more to the financial picture of the Coal Creek units once these tax benefits expire. What the data show is a plant that will be on precarious financial ground after losing the DryFining tax benefits.

As recently as 2014, the units earned upwards of $99 million in estimated profit, though this was likely due in large part to the cold snap in early 2014 that pushed power prices to higher than normal levels. We calculated this estimated profit by comparing estimated MISO revenue to these units to their estimated variable costs in 2014. However, starting in 2015, the picture changed dramatically. That year, using the same methodology, the units earned only $6.4 million in profit, excluding consideration of both their fixed O&M costs[9] and the tax benefits of the DryFining technology. The following year, 2016, was even financially worse. Again, without consideration of the DryFining tax benefits or Coal Creek's fixed costs, Coal Creek lost an estimated $3.3 million. On the same basis, through May of 2017, Coal Creek has made a profit, but it is only $2.1 million. Indeed, all of the foregoing analysis of Coal Creek's economics has

[8] Great River Energy's Response to CEO IR 39 (July 31, 2017).
[9] SNL Financial estimates that $32.5 million was spent on fixed O&M costs in 2015. Fixed O&M costs are properly included in going forward profitability decisions because those costs are "avoided" by retiring the units.

been conservative because it largely does not include fixed O&M, which can be avoided by retiring the units.

The impact of the sunsetting of the DryFining IRS benefits is extremely likely to make the Coal Creek units unprofitable from any standpoint. This is because fuel is the primary operational cost as shown in Figure 4.

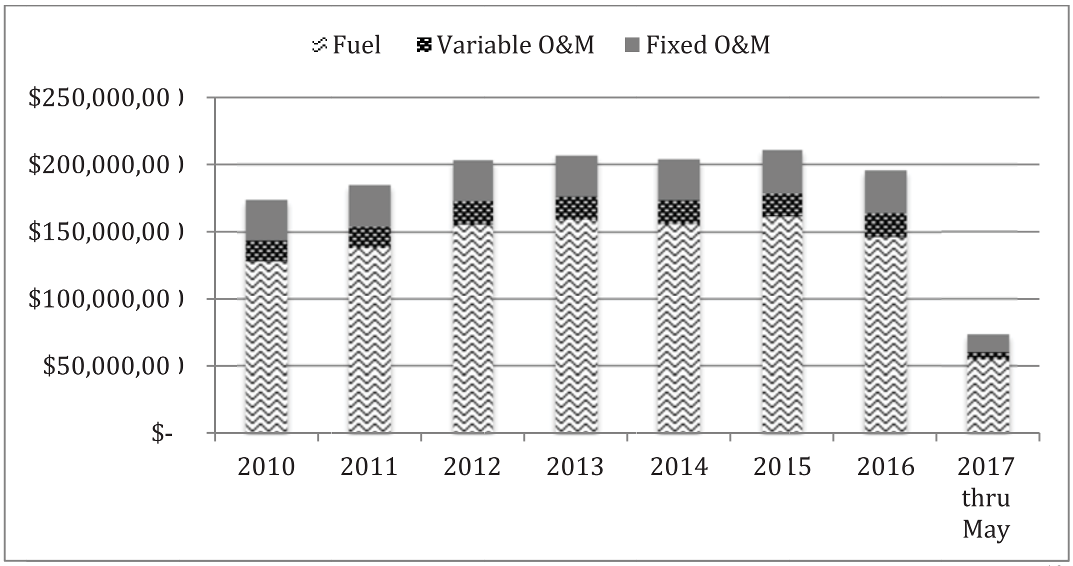


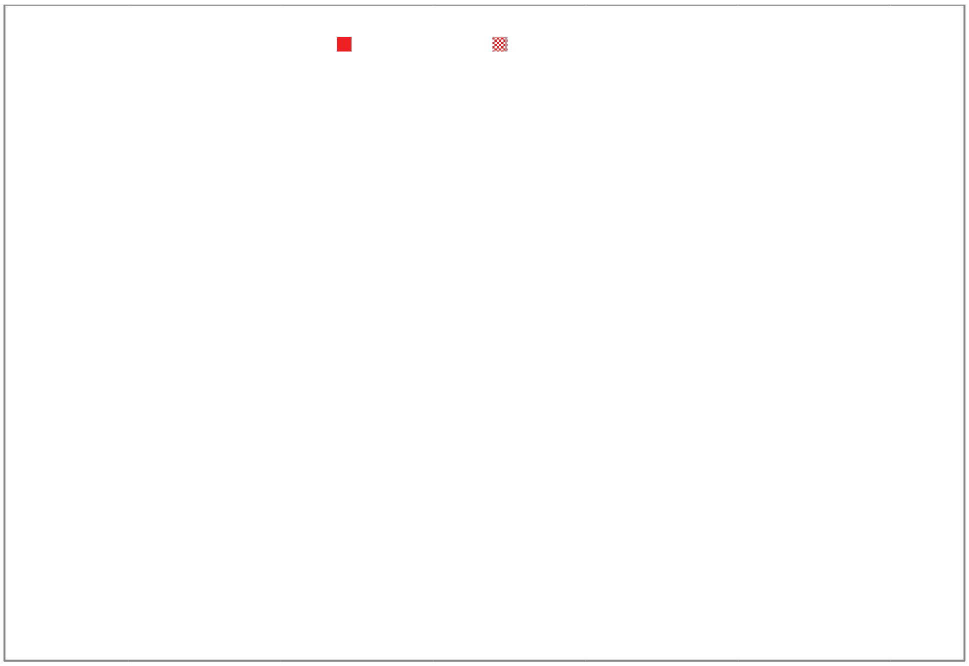
Figure 4. Estimated Coal Creek Operating Costs by Type, 2010 – May 2017[10]

If we examine the data contained in GRE's "Expected Values" case, the financial picture of these units looks just as dismal. Figure 5 was created using GRE's own modeling data for Coal Creek's future costs. But because GRE's fixed O&M includes the unamortized plant balance, which is not appropriately included in a plant viability analysis, we also include a scenario using the SNL Financial's estimated fixed O&M, which does not include the unamortized plant balance. We refer to the scenario with SNL fixed O&M as "best case" and the scenarios with GRE's fixed O&M as "worst case."[11] The reality will be somewhere in between

[10] Based on data from EIA Form 923, MISO, and SNL Financial.
[11] This type of plant viability analysis is distinct from consideration of the short-run economics of Coal Creek. In the latter, properly categorized operating expenses between "fixed" and

the “best” and “worst” cases. The “best” does not include future capital expenditures, which are avoidable with retirement. The “worst” includes the unamortized plant balance, which cannot be avoided by retirement. Both estimates of cost are compared to GRE’s own forecast of forward prices at the MISO Minnesota hub.

[TRADE SECRET BEGINS



TRADE SECRET ENDS]

Figure 5. Coal Creek’s Future Economic Viability

Once the DryFining tax benefits sunset in 2020, Coal Creek will stand to lose **[TRADE SECRET BEGINS TRADE SECRET ENDS]** of dollars. This all suggests that GRE should seriously evaluate retirement of Coal Creek, as ordered by the Commission in the last IRP.

“variable” is important, but in the former it is immaterial whether operational costs are categorized as fixed or variable - both need to be included since they are “avoidable” by retirement.

C. GRE's Coal Creek Retirement Analysis Was Flawed.

1. GRE's preferred plan does not consider commission externality values and CO_2 regulatory costs

In its Order on GRE's last IRP, the Commission stated, "[t]he Commission will direct GRE to continue the practice of selecting a reference case scenario from among the scenarios that apply the Commission-approved externality values and CO_2 regulatory costs."[12] Despite this clear directive, GRE's Preferred Plan is one of its "Expected Values" model runs, which all ignore the Commission's externality and regulatory values. Moreover, GRE justifies its selection of the Preferred Plan because "[a] range of sensitivities run off the Expected Values Case provides insight into the robustness of the Preferred Plan."[13] But of the 67 runs performed, only 18 of them include externalities or regulatory values. GRE refers to these runs as "reference case" runs, but we do not interpret the Commission's Order point to be directing GRE to simply adopt a naming convention. We understand the order point as directing GRE to embed the externality values and CO_2 costs into the majority of its runs. GRE has clearly violated Commission direction in the selection of its preferred plan, and, as discussed below, this has implications for how the Coal Creek retirement scenarios should be viewed.

2. Coal Creek replacement was not fairly and realistically evaluated

Given the likelihood that Coal Creek will become uneconomic to run in the near future, we paid particular attention to the question of how GRE modeled retirement and analyzed alternatives to those units. As we discuss below, GRE's modeling does not result in a fair and realistic evaluation of retiring Coal Creek.

---

[12] Order Denying Motion to Compel, Accepting Resource Plan, and Setting Future Filing Requirements, 9 (Oct. 26, 2015) Docket No. ET2/RP-14-813.
[13] Great River Energy's 2018 – 2032 Integrated Resource Plan, Docket No. ET2/RP-17-286, 117 (May 1, 20170 (hereinafter GRE 2018 IRP).

a) GRE did not consider realistic replacement resources.

Using the so-called Reference Case, which includes what the Commission's established mid-range of externality values was at the time, GRE considered four different retirement dates, in 2020, 2024, 2028, and 2030. The Net Present Value (NPV) of each run plus that of the Reference Case without retirement of Coal Creek is given in Table 2.

Table 2. NPV of Reference Case with and without Coal Creek Retirements

[TRADE SECRET BEGINS

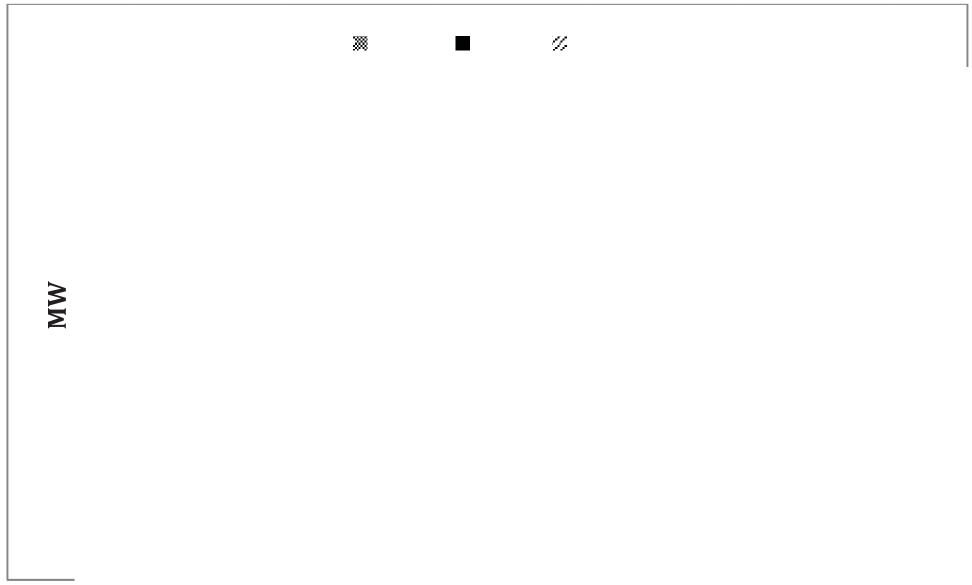
TRADE SECRET ENDS]

GRE's own modeling appears to show that early retirement of Coal Creek in 2024 is the *least* expensive alternative,[14] and retirement in 2020 appears the most expensive. However, the NPV difference of the 2020 retirement case is largely due to flaws in GRE's modeling assumptions and not a realistic assessment of the situation.

The modeling run in which Coal Creek is retired in 2020 includes the following resources as shown in Figure 6.

[14] Despite these results, GRE claims that "[w]hen the model was allowed to economically select retirement of the station, it did not retire it under normal and expected conditions. This means it is more cost-effective to continue to operate the plant than to retire it." (GRE 2018 IRP at 135). This would seem to indicate a flaw in GRE's modeling since it is contradicted by GRE's own analysis of Coal Creek retirement.

[TRADE SECRET BEGINS



TRADE SECRET ENDS]

Figure 6. Resources added from 2018 – 2025 in Reference Case with CCS Retirement in 2020

System Optimizer adds nearly **[TRADE SECRET BEGINS TRADE SECRET ENDS]** of reciprocating internal combustion engine (RICE) capacity simply because there is no other realistic resource made available to the model to meet the deficit of capacity created by the retirement of the Coal Creek units in 2020. GRE did not model any short-term capacity contracts. And although wind and solar are also made available by 2020, System Optimizer does not appear to be able to add enough capacity to cover the shortfall made by the retirement of Coal Creek. Even if it could, those resources provide expensive capacity, but cheap energy, because their contribution to peak demand is discounted by 50 to 85 percent from their nameplates.

The capital costs alone of the RICE units represent **[TRADE SECRET BEGINS TRADE SECRET ENDS]** or approximately 13% of the total NPV. There is nothing about this proposition that is realistic. RICE units are typically built in small quantities to meet peak needs where other resources are not available. They are expensive to build and operate and do not, in any way, make sense as a replacement for the Coal Creek units. Nor is their dispatch simulated in a way that makes sense for these units. As soon as they come online in January 2020, the Reference Case plus Coal Creek retirement in 2020 run has them operating at **[TRADE SECRET BEGINS TRADE SECRET ENDS]** capacity factor, a number that is unrealistically high for this type of unit in the MISO system.

The reference case run in which Coal Creek retires in 2024, by contrast, adds approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]** of combined cycle capacity in addition to **[TRADE SECRET BEGINS TRADE SECRET ENDS]** of wind and solar capacity in the years leading up to and including 2024. And again, this plan is significantly cheaper than the plan in which Coal Creek continues to operate through the end of its book life. This suggests that, at a minimum, GRE should seriously be considering retiring the plant in that time frame.

GRE should have made the 2020 retirement case more realistic by doing two things. First, it should have provided the option to use a capacity purchase contract to bridge the gap between retirement and new resources. Second, it should have allowed System Optimizer to reflect the value of higher demand-side management savings in Coal Creek retirement scenarios.

GRE contends that, "RICE resources could also be considered a proxy for bilateral contracts, which could offer bridge capacity or energy."[15] But this greatly overstates the likely costs of those contracts. Many of these contracts are short term and fall well under the cost of a

[15] GRE 2018 IRP at 116.

new RICE unit,[16] which is approximately $112 per kw-month[17] if it were spread out over 12 months to give a roughly apples to apples comparison.

b) GRE's modeling of demand-side resources is flawed.

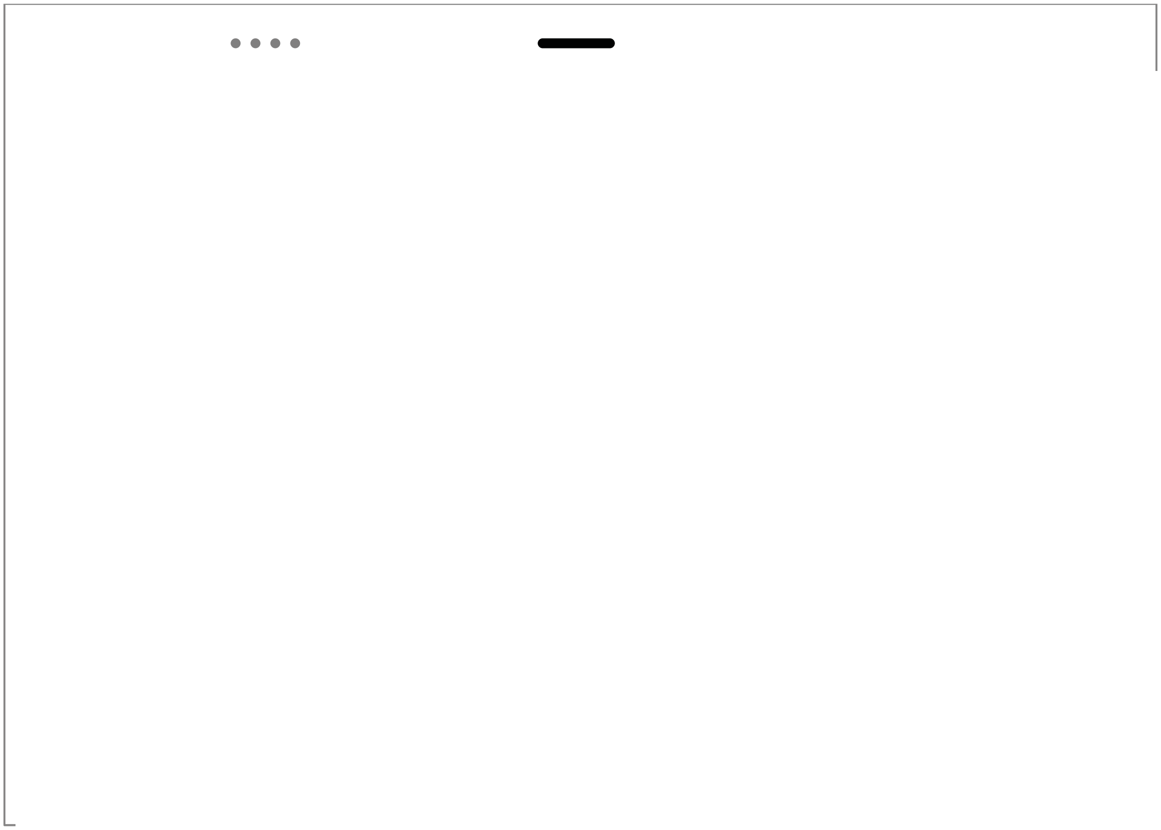
In addition, to accurately model the availability of bilateral contracts, GRE should modify its modeling so that demand-side resources are actually reflected in System Optimizer. What GRE has presented here is almost entirely concerned with the supply-side and assumes that energy efficiency and demand reduction savings are baked into the load forecast. It performed a few sensitivities that included higher levels of energy efficiency savings, but none that also considered the retirement of the Coal Creek units, which would likely increase the value of those savings.

There are numerous problems with GRE's approach to energy efficiency savings:

1. The level of savings modeled in these DSM sensitivities is not transparent because they are not presented anywhere in the IRP.
2. At present, GRE is in an extremely long capacity position and assumes it will remain so for many years to come if none of its units retire (see Figure 7 below). All DSM sensitivities were modeled only under the assumption that its long position continues, which shows stakeholders, the Commission, and GRE members only a partial picture of the value of energy efficiency to GRE's system. While GRE tests sensitivities of multiple factors like zero load growth, low/high market prices, low/high natural gas prices, those runs are of limited value because they simply test GRE's portfolio under the presumption that this excess of capacity continues.
3. Demand response was not modeled at all. The modeling says nothing about the value to members of increased demand response in any scenario, nor the types of demand response that would give the most value, e.g., summer vs. winter, or an expanded water heater program vs. focusing on air conditioner cycling.

[16] For example, the contracts we received in response to CEO IR No. 1 range from **[TRADE SECRET BEGINS TRADE SECRET ENDS].**
[17] GRE 2018 IRP, App. C at 2.

[TRADE SECRET BEGINS



TRADE SECRET ENDS]

Figure 7. GRE's Reserve Margin is Expected to Be Well Above Reserve Margin Requirements Under its Preferred Plan[18]

GRE's analysis does not comport with the Commission's Order on GRE's 2014 IRP. In that Order, the Commission directed GRE to:

> [E]mploy its capacity expansion model to conduct a more thorough review of demand-side alternatives. In future resource plans GRE must evaluate how changing the targeted level of conservation, all else being equal, would affect the rest of GRE's plan. By holding other variables constant, this analysis will enable parties and the Commission to have a stronger understanding of the costs and benefits of different levels of conservation, independent of other changes.[19]

The only energy efficiency sensitivities GRE evaluated were conducted under the Expected Values case and without regard to Coal Creek retirement. This approach does not give

---

[18] Great River Energy's Response to CEO IR 1 (May 26, 2017).

[19] Order Denying Motion to Compel, Accepting Resource Plan, and Setting Future Filing Requirements, 9 (Oct. 26, 2015) Docket No. ET2/RP-14-813.

an accurate picture of how cost-effective Coal Creek retirement could be with varying levels of energy savings and demand response.

3. GRE did not model current and likely wind and solar prices.

Resource alternatives need to be modeled based on costs that are current and likely. GRE relied heavily on AEO information to predict the cost of new resources including wind and solar.

GRE modeled wind at a cost of $1,877 per kW in the self-build case or $35 per MWh on a PPA basis. Xcel's recent request for proposals for new wind yielded over 30 proposals with costs below $22/MWh.[20] Notably, when GRE adjusted its cost of wind to $25 per MWh under reference case assumptions, System Optimizer took all the wind it could in 2018 and 2019 or 2,000 MW total.

GRE also modeled solar at higher than likely prices at $65 per MWh on a PPA basis or $2,671 per kW in the self-build case. The cost of solar has come down dramatically and is expected to continue to decline with most utility scale solar projects coming in at costs well below $2,000 per kW.[21] Even GRE's most aggressive lower cost sensitivity for solar did not capture these price reductions. It also modeled a 5 percent annual reduction in overnight/PPA cost. But that trajectory never puts the PPA price on par with today's prices, and the self-build price does not reach parity until roughly ten years down the road.[22]

[20] Initial Comments of Fresh Energy, Minnesota Center for Environmental Advocacy, Sierra Club, and Wind on the Wires, 3, Docket No. E002/M-16-777.
[21] Solar Industry Update Q3/Q4 2016, U.S. Department of Energy, 24, (Dec. 21, 2016), available at https://www.nrel.gov/docs/fy17osti/67639.pdf.
[22] Great River Energy's Response to CEO IR No. 1 (May 26, 2017).

By using higher than likely prices for wind and solar, GRE underestimates the value these resources can provide GRE's system across all scenarios of future resource mixes and makes the model less likely to choose renewable resources over fossil fuels.[23]

III. GRE'S ENERGY FORECAST IS UNRELIABLE.

A. GRE's Regression Analysis Is Unreliable.

In addition to the modeling errors surrounding the analysis of Coal Creek retirement, GRE's load forecast that supports its preferred plan is not reliable. GRE used a regression analysis to develop its demand forecast. Regressions are useful in finding patterns in large data sets (hundreds of entries and, more often, thousands or even millions), but with annual data for as few as 23 years, GRE should justify the value added from using a regression to show data patterns. Without such a reason, a more transparent method—like extrapolating the linear growth trend from recent years—would have been more appropriate.

On top of GRE's questionable use of a regression analysis, there are at least three other flaws in the regression analysis that GRE uses to justify its energy forecast. First, GRE should not have run its regression after it removed certain variables and related data. Second, the methodology washes out the pattern of recent years, because it equally weighs the pattern of

[23] As a final note about the flaws in GRE's modeling, during our review of GRE's IRP, we noted that some costs seem to escalate consistently with GRE's inflation assumption of 2.5 percent, while others do not. During a June 27, 2017 call with GRE staff, we asked whether costs were modeled in real or nominal dollars, and staff told us the intention was to model nominal dollars, but agreed that certain costs were not modeled in this fashion. We noticed this issue primarily for existing resources whose early retirement was not explored in GRE's modeling, including Spiritwood Station, Trimont wind, and Elm Creek wind, so this problem is less significant than it could otherwise be. We mention this, however, so that GRE can rectify this problem in future IRPs because the cumulative impact of twenty years of inflation can certainly be significant when it comes to dispatch, acquisition of new resources, and retirement of existing resources.

energy consumption from more distant years. Finally, GRE uses All-Requirements members' *future* energy requirements to help forecast regional energy requirements.

First, GRE has excluded all variables that were not statistically significant (that is, not differentiable from random noise) in its regression, and then reran the regression without these variables.[24] Leaving these variables in final regression analysis and results is both the most transparent practice and serves to show data patterns in the context of the full set of potential influences.

GRE not only excluded these variables from the analysis, but also removed information and data for these variables from its spreadsheets and (with a few exceptions) from the IRP report and appendices. Lack of statistical significance is not a reason to remove a variable from a regression. And there is no excuse for removing data related to those variables, making it impossible for stakeholders to fully review GRE's regression analysis.[25] GRE fails to explain its deviations from standard practice.

Second, the structure of GRE's regression analysis results in the attribution of equal weight to all past years in predicting a future pattern of annual energy growth. Given the important structural changes that have taken place in the U.S. energy sector since the 1970s, it seems extremely unlikely that energy use in 1977 is just as important as that of 2014 in predicting future energy use. Because GRE has given equal importance to all past years, the influence of flat and declining energy use in the past five years is washed out by rising demand in the previous three decades. The use of regression analysis here gives a facade of scientific

[24] Great River Energy's Response to CEO IR No. 2 (May 26, 2017). Metro region excludes heating degree days and residential propane prices. Northern region excludes cooling degree days and residential propane prices. Southern and Western region excludes employment rate and cooling degree days.
[25] Great River Energy's Response to CEO IR No. 49 (Aug. 14, 2017).

accuracy that may be obscuring a more common sense expectation of flat to declining energy use.

Finally, GRE seemingly uses *future* All Requirements energy demands (AR(1) in Table 3 below) as an explanatory variable in its *regional* energy requirements forecasts.[26] All Requirements energy is not listed as an independent variable in GRE's Appendix D – Trade Secret Forecast,[27] yet it is included in the tables showing the Metro and Northern region model regression coefficients, t-statistics, and p-values.[28]

Table 3. [from Public Appendix D] Metro Region energy model regression coefficients, T-Stat, and P-Values.

Variable	Metro Region Coefficient	StdErr	T-Stat	P-Value
Constant	10.56891927	0.897747492	11.7727082	8.40925E-14
LN(Metro Region Residential Consumers$_{-1}$)	0.746144672	0.150492503	4.95801888	2.0471E-05
LN(Metro Region Employment$_{MA\ 2}$)	0.481956285	0.174604786	2.76026961	0.009356624
LN(Metro Region CDD$_{65}$)	0.062159596	0.009378503	6.62788074	1.37271E-07
LN(Wholesale Sale Rate Real$_{MA\ 3}$)	-0.119864176	0.027048174	-4.4315071	9.66331E-05
AR(1)	0.74009516	0.126725186	5.84015838	1.45903E-06

Table 4. [from Public Appendix D] Northern Region energy model regression coefficients, T-Stat, and P-Values.

Variable	Northern Region Coefficient	StdErr	T-Stat	P-Value
Constant	5.148662131	1.081242643	4.76180084	3.44397E-05
LN(Northern Region Residential Consumers$_{-1}$)	1.275099162	0.082908384	15.3796166	1.23541E-17
LN(Northern Region HDD$_{65}$)	0.259551746	0.048129601	5.39276748	5.13763E-06
LN(Northern Region Employment/Population)	0.746286089	0.155420599	4.80171929	3.05631E-05
LN(Wholesale Rate Real)	-0.098412651	0.033209055	-2.9634283	0.005523806
AR(1)	0.394126021	0.150840627	2.61286384	0.013277429

The use of this variable is circular. Where would GRE derive future All-Requirements members' energy requirements except through the very regression analyses GRE is performing? And even if there were a reliable source of future All-Requirements members' energy requirements, how can energy requirements "explain" energy requirements?

[26] GRE's energy requirements regressions are divided into Metro, Northern, and Southern & Western regions and are intended to forecast All-Requirements consumption in each of those regions.
[27] GRE 2018 IRP, App. D "Independent Variables" section of Trade Secret Forecast.
[28] GRE 2018 IRP, Public App. D at 44, 45, Tables 3 and 4.

B. GRE's Energy Forecast Conflicts With Its Recent Sales History.

Using GRE's response to CEO IR 3 and its Annual Reports we constructed the following graph. We assumed forecasted energy requirements for the line losses identified in Table 9 of GRE's IRP.

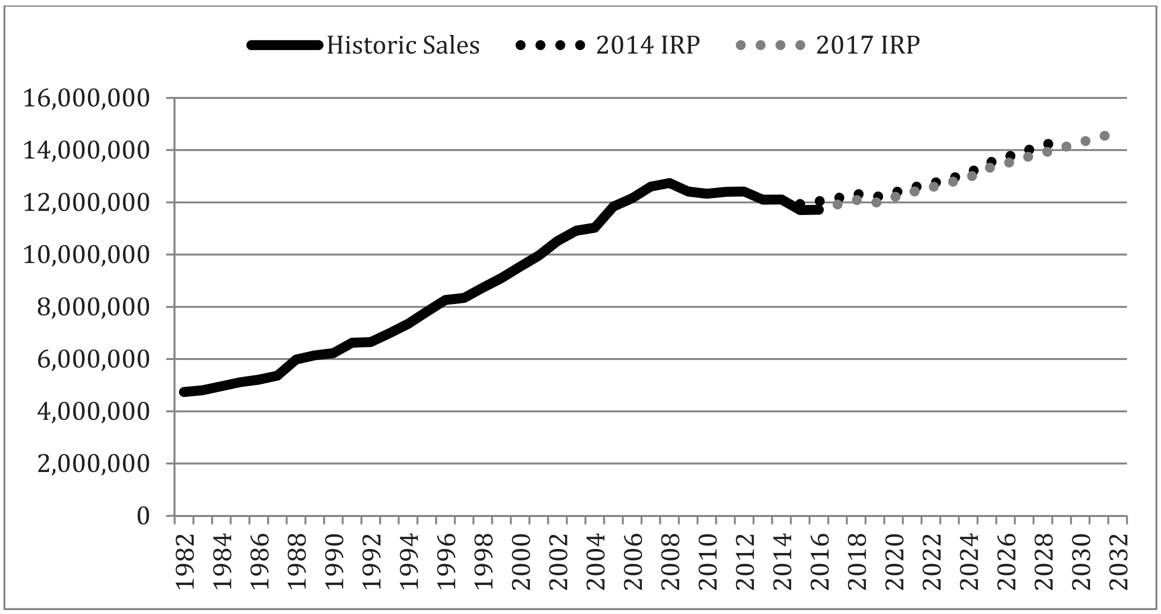


Figure 8. GRE Historic Sales and 2014 and 2017 IRP Sales Forecasts, 1982-2032

The trend forecasted in GRE's IRP is clearly at odds with recent experience. In fact, while GRE has generally experienced declining sales since 2008, GRE's load forecast projects that sales increase at a rate not seen in over a decade. In the past five years, sales have declined 5.6 percent, but GRE forecasts that sales will increase 4 percent over the next five years even taking into account the 2019 loss of Elk River Municipal sales of 290,930 MWh.[29] This is likely at least partially due GRE's choice to equally weigh sales data from more than a decade ago with GRE's recent sales in its regression analysis.

[29] GRE 2018 IRP at 95, Table 9.

GRE appears to have simply applied a trend similar to that identified in its 2014 IRP sales forecast to its current (2017) IRP sales forecast. This surprising modeling choice can be seen more clearly in Figure 9, which shows the year-on-year growth rate of both forecasts.

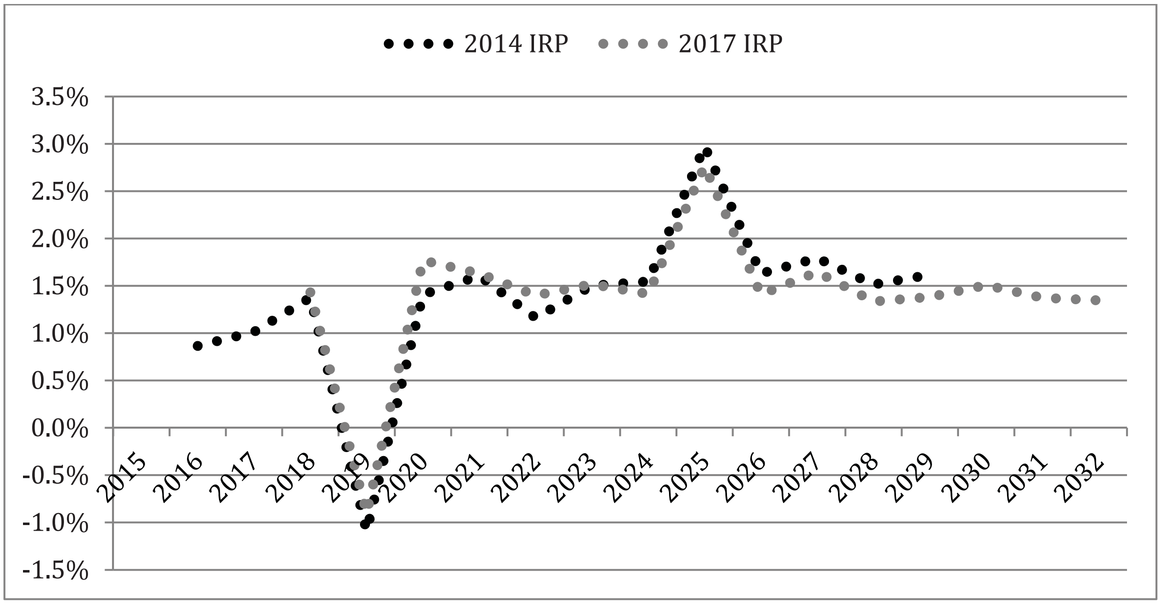


Figure 9. Growth rates in GRE's 2014 and 2017 IRP Sales Forecasts.[30]

The absolute level of sales forecasted in the 2014 IRP (shown in Figure 9) is higher in any given year than that forecast in the 2017 IRP largely because the 2017 IRP forecast is starting from a lower sales number. This results in, for example, 2020 sales projected to be 12,367,884 MWh in the 2014 IRP, but 12,294,962 MWh in the 2017 IRP – a difference of 1.5 percent.

In order for GRE's sales forecast for 2017 to be accurate, sales would have to increase in just this year by 1.7 percent[31] – an annual increase that GRE has not experienced in a decade. If

[30] Great River Energy's Response to CEO IR No. 3 (May 26, 2017).
[31] 2016 sales were 11,716,895 MWh and 2017 forecast sales are 11,921,713.

all of these numbers were presented without including the Fixed Requirements members, whose load does not change from year to year, the difference would be even larger.[32]

The load and energy forecast is one of the single most important inputs into an IRP and yet GRE has failed to adequately analyze what is the most likely scenario for load growth. Even its "low" forecast still assumes increasing sales.

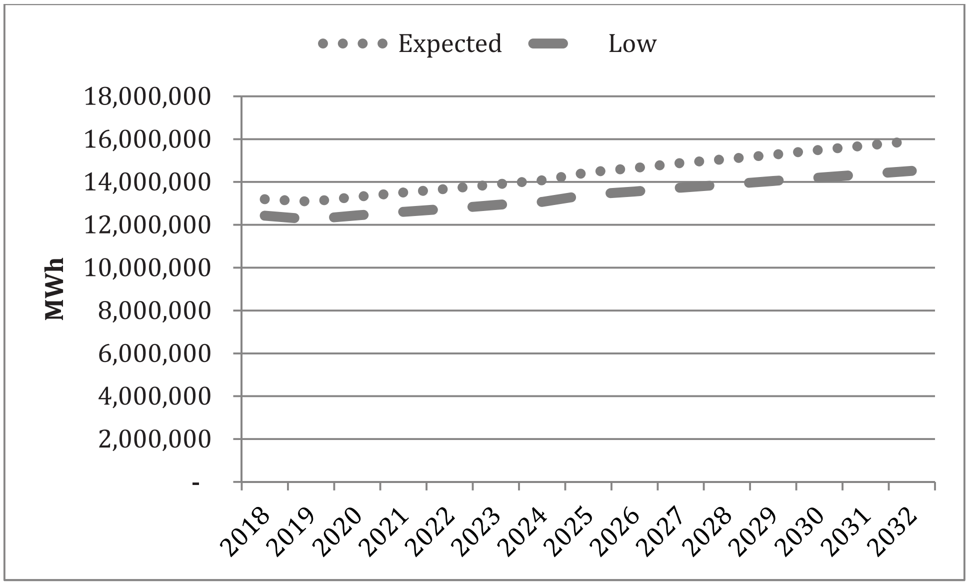


Figure 10. GRE's Expected and Low Forecasts[33]

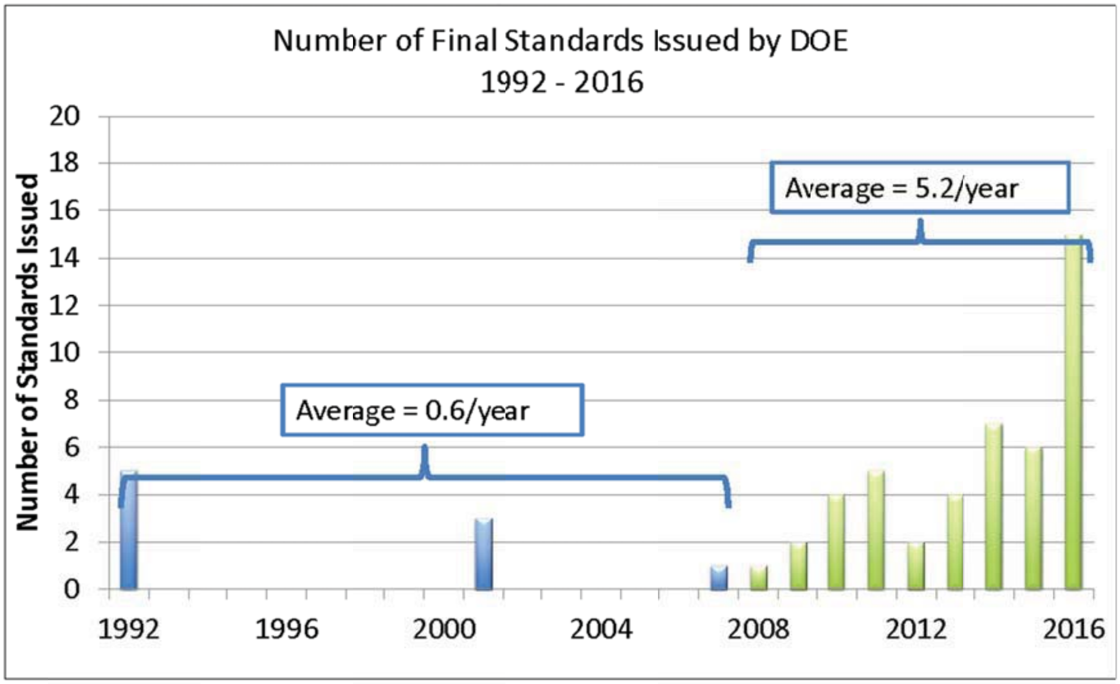
GRE also ran a single System Optimizer scenario with zero load growth, but this scenario does not rectify the fundamental flaw in GRE's IRP of failing to consider a more realistic sales forecast in all other scenarios.

[32] Note that electrification of new loads cannot explain this trend because no term intended to reflect new loads was included in GRE's base energy forecast. Nor would it be reasonable to expect that electrification of new loads could increase sales by 1.7 percent in 2017 alone.

[33] Great River Energy's Response to CEO IR No. 3. (May 26, 2017) (note that this figure shows energy requirements, not sales).

C. New Federal Appliance Standards Will Continue To Impact GRE Sales

Even if GRE's regression analysis had been properly specified and executed, it could not fully take into consideration additional federal appliance standards that will come into force during the study period.



*As of January 3, 2017 Source: ASAP/ACEEE and US DOE

Figure 11. Number of Appliance Standards Issued by DOE, 1992-2016.[34]

Relying on historical sales to incorporate the impact of these standards is not a robust solution, because at least some of the years relied upon have much lower rates of appliance standard adoption. The adoption of these standards will definitely reduce the overall potential for EE savings on any utility's system, but we have seen no evidence to support the assumption that only 1 percent annual incremental savings is achievable in light of these standards.

In sum, GRE's sales forecast is not predicated on a methodology that is robust nor does it square with GRE's last decade of sales.

[34] Michigan Public Service Commission Integrated Resource Plan Stakeholder Group Meeting (May 1, 2017) slide 11 available at http://www.michigan.gov/documents/mpsc/May_1st_-_Lawrence_Berkeley_National_Laboratory_Presentation_Slides_560420_7.pdf.

IV. GRE'S ANALYSIS OF ENERGY EFFICIENCY DOES NOT COMPORT WITH THE 2014 IRP ORDER.

In its Order on the 2014 IRP, the Commission required GRE to perform several analyses with respect to energy efficiency:

1. [P]resent a discussion of the types of customers served by GRE's individual member distribution cooperatives, and the unique opportunities for conservation that individual retail customers – commercial, industrial, and residential – may provide.
2. Provide detailed documentation of its strategies for achieving supply-side energy efficiency savings [and] the savings these strategies have achieved.

We address whether GRE has satisfied each requirement in turn. First, with respect to the discussion of the types of customers served by GRE's individual member distribution cooperatives, and the opportunities for conservation, GRE claims that Appendix K "shows the composition of individual member energy sales by class." But Appendix K simply contains the 2008 – 2015 level of CIP savings for each member cooperative. GRE also claims that Section 6 of its IRP "discusses the limitations and opportunities that are present in evaluating conservation programs with disproportionately residential service territories."[35] However, this section presents virtually no new information. This section discusses the impact of the EISA lighting standards, which became *law over a decade ago*, and it cites back to an EPRI study of energy efficiency potential from 2011, the flaws of which were addressed in our comments on GRE's 2012 IRP.

GRE has made no meaningful effort to discuss customer types and opportunities for conservation as the Commission required in its last order.

Second, with respect to the detailed documentation of its strategies for achieving supply-side energy efficiency savings and the savings these strategies have achieved, GRE devotes just a

[35] GRE 2018 IRP at 133.

page to this topic[36] and does nothing more than list activities, roughly half of which seem to be plant-related modifications and at least some of which have already apparently happened. In fact, the list presented at this page is nearly identical to a list of supply-side measures GRE says it was considering back in 2013.[37] With respect to savings, GRE does nothing more than to say that the sum of supply side projects GRE has executed have yielded 0.5 percent energy savings. Nor is there any indication that these measures provide energy savings that result in energy efficiencies greater than what would occur through normal maintenance activity[38] as required by Minnesota Statutes. So-called "flexible operations" at Coal Creek are on this list, but GRE has never argued that change was made for the sake of achieving greater efficiency. Instead, it has made representations to us and in the media that this change was made due to changing MISO market conditions.[39] It is difficult to see how any of this represents a good faith effort to address the Commission's requirement.

We are concerned that there may be hostility to energy efficiency on GRE's part that is percolating down to its member cooperatives. That hostility is exemplified in part by the continued use of a flawed LADCO analysis to project energy efficiency costs. As we discussed in our comments on GRE's 2014 IRP:

> LADCO used "Utility Net Benefit correction factors" agreed to in Docket No. E,G999/CI-08-133 to escalate the incentive and administrative costs. Those factors were intended to correct for non-linear benefits of energy efficiency under the assumption that the rate of increase in net benefits from implementing energy efficiency programs would flatten as savings increased since the cost of those programs would increase non-linearly. Because the financial incentives for energy savings are calculated based on net benefits, without this adjustment, the incentives would accrue at a slower rate as greater penetration of savings was achieved. However, two years later, the Commission removed this adjustment

[36] *Id.* at 132.
[37] Reply Comments of Great River Energy, 8 Docket No. ET2/RP-14-813 (May 1, 2015).
[38] GRE 2018 IRP at App. E, 2, n. 5.
[39] Matyi, Bob, *ND coal plant returns to its 'cycling' past.* S&P Global Platts, (Dec. 28, 2016).

> after the DOC concluded that the increase in net benefits did not in fact slow as greater savings were achieved.[40]

And yet LADCO again in this IRP uses these factors to project future costs of energy efficiency.

Even if these factors could be correctly used to project future costs of energy efficiency, their application is flawed. LADCO concludes, without support, "[s]ince GRE has a lower proportion of commercial and industrial customers than the IOUs, its savings percentage would be expected to be lower, given the same effort of implementation."[41] Presumably based on this unsupported assertion, LADCO goes on to conclude that "[s]ince a 1.0% of sales plan for GRE is consistent with a 1.5% of sales plan for the IOUs, the factors used to increase an IOU plan from 1.5% to 3% are the same factors used to escalate the GRE plan from approximately 1% to 2%." The use of these factors and their application to projected costs is without merit.

In its reply to our comments on its 2014 IRP, GRE contended that "conservation and energy efficiency technologies have changed significantly since 1990, and the costs to achieve the same amount of savings have increased." The experience of the other Minnesota utilities contradicts this. Figure 12 shows the first-year cost per kWh of energy efficiency achieved by Xcel, Otter Tail Power, Minnesota Power, and IP&L.

[40] Environmental Intervenors' Initial Comments on Great River Energy's Cooperative's Integrated Resource Plan, 5 Docket No. ET2/RP-14-813 (March 2, 2015).
[41] GRE 2018 IRP App. F, at 1.

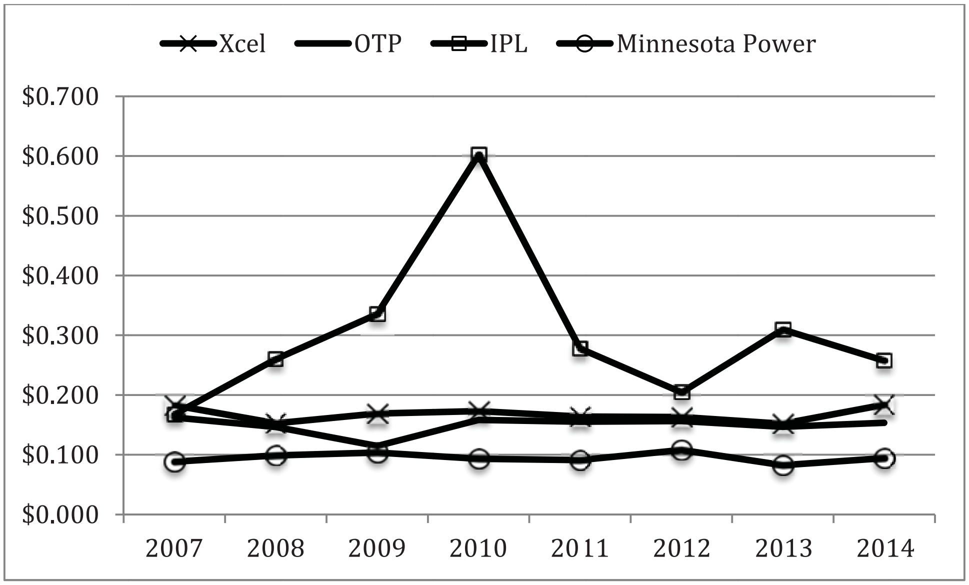


Figure 12. First Year Cost of Energy Efficiency, 2007 – 2014.

Costs have been historically flat for all the utilities except IPL. This is true even as savings as a percentage of sales have trended upward as shown in Figure 13.

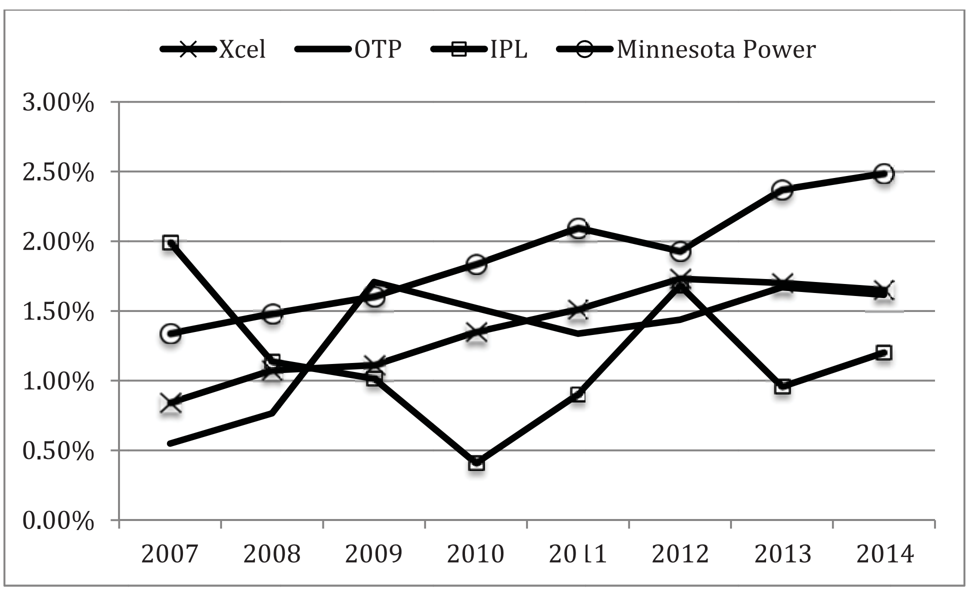


Figure 13. Savings as a Percentage of Sales, 2007 – 2014.

Even if LADCO had appropriately constructed its analysis, the Base Case first year cost, which is an extension of the 2017 CIP, is *less* than that of Xcel, IP&L, and Otter Tail Power. This is possible evidence that GRE member cooperatives are, collectively, selecting only the cheapest and easiest measures to install. But it is also contradictory that on the one hand GRE's program could be among the cheapest in the state of the Minnesota, and on the other be argued that GRE member cooperatives encounter such unique and special difficulties in reaching rural, residential customers that their program savings can go no higher.

Table 5. First-Year Cost Per kWh as Calculated by LADCO by Scenario

Base Case	1.25%	1.5%	2.0%
$.126	$.194	$.246	$.342

But even assuming that the net benefit correction factors can be used to forecast future energy efficiency costs, that the factors were correctly applied, and that GRE member cooperatives would have to spend significantly more to achieve more savings, the LADCO analysis still shows that the utility benefit cost ratio of achieving the 2.0% scenario is 1.88.

LADCO and by extension GRE are concerned the Ratepayer Impact Measure (RIM) test results. But as this Commission doubtlessly understands well, the RIM test does not compare rate increases with and without energy efficiency. Nor should it be surprising that EE programs would fail the RIM test because they are designed to minimize *bills*, not rates.

GRE's real concern seems to be summed up in the last paragraph of LADCO's report:

> Existing conservation efforts, combined with naturally occurring conservation caused by more strict equipment efficiency standards and personal choice, along with other factors, resulted in relatively flat sales growth over the past several years. Increasing conservation efforts above the current level may likely result in negative load growth and higher rates for customers.

As we discussed in Section III. B., there is reason to believe that negative load growth is already here and may be for quite some time to come. But ignoring this trend and eschewing cost-effective energy savings that will potentially save customers money is not a constructive way to address this problem.

V. EXPANSION OF GRE'S ELECTRIC THERMAL STORAGE PROGRAM COULD PROVIDE OPPORTUNITIES FOR ENVIRONMENTALLY BENEFICIAL ELECTRIFICATION

GRE provides information on its efforts to advance environmentally beneficial electrification use in its grid modernization appendix.[42] GRE states that the converging trends of technological progress on efficient electric devices and a cleaner electric system are making the case for using electricity to power more of our economy. In addition, the Company states that it will "encourage environmentally beneficial electrification initiatives" in its Five-Year Action Plan.[43] GRE includes community energy storage, such as controllable electric water heaters, as part of this initiative. As discussed below, although GRE's current electric water heater program can reduce peak demand costs, provide cost-competitive options for customers, and drive long-term demand for wind resources, it should be considered environmentally beneficial electrification only to the extent that the utility creates a low-carbon electric generation portfolio, or pairs its program with renewable pricing options. Therefore, we recommend that the Company provide a detailed plan of how and when it will expand its electric water heater program in reply comments in this docket, as well as how and when it will make the program environmentally beneficial compared to other fuel sources.

GRE indicates that as of June 2017, GRE's members have 66,123 off-peak electric thermal storage (ETS) water heaters and 45,406 peak shave water heaters.[44] GRE describes these two types of resources as follows:

- Off-peak ETS water heaters: designed to heat water only during off-peak hours, or from 11pm-9am on weekdays during summer months, 11pm-7am on weekdays during winter months, weekends, and holidays.[45] These water heaters are intended to hold sufficient hot

[42] GRE 2018 IRP App. G.
[43] GRE 2018 IRP at14.
[44] Great River Energy's Response to CEO IR No. 21 (July 31, 2017).
[45] Great River Energy's Response to CEO IR No. 24 (July 31, 2017).

water throughout the day to avoid the need to charge outside of off-peak hours under normal hot water consumption levels. These water heaters operate under these parameters all the time.

- Peak shave water heaters: designed to allow normal water heating to occur throughout the year, except when GRE is expecting a peak demand event day between 2pm and 8pm.[46] For example, if GRE is expecting a hot weather day with significant air-conditioning load in August it can call on these water heaters to not operate between 2pm and 8pm. This helps minimize expensive peak demand on high-demand days. GRE indicates that of the 380 MW of demand response programs in the summer of 2016, 25 MW was due to load reductions from peak shave water heaters.[47] These water heaters operate normally except for the few days and hours during the year that GRE determines are critical peak days, typically during the summer.

These programs provide tangible benefits to GRE, its distribution member cooperatives, and their customers. Notably, reducing peak demand avoids costs related to purchasing needed energy on the MISO market or building additional peaking generation plants.

In addition, for customers on the off-peak ETS water heating program, GRE and its members offer upfront rebates and a discounted rate for the energy used by the water heater. This program makes electric water heaters cost competitive with natural gas water heaters from a customer's point of view. According to CEOs' analysis highlighted in Attachment A, over the life of the water heaters, installing an electric water heater under GRE's off-peak ETS program is a cost-competitive option for customers in GRE's territory compared to other fuel sources. We also provide life-cycle cost for a customer with an electric water heater in Connexus' service territory, but not on the GRE program, to highlight the value of GRE's discounted rate to make this option cost competitive.

Shifting load from daytime peak hours to overnight low-use hours has long-term environmental benefits by driving demand at times when wind energy production is highest. As

[46] *Id.*
[47] Great River Energy's Response to CEO IR No. 21 (July 31, 2017).

seen in 'igure 14, wind energy production was highest luring night ime hours when demand on the system was lowest.[48]

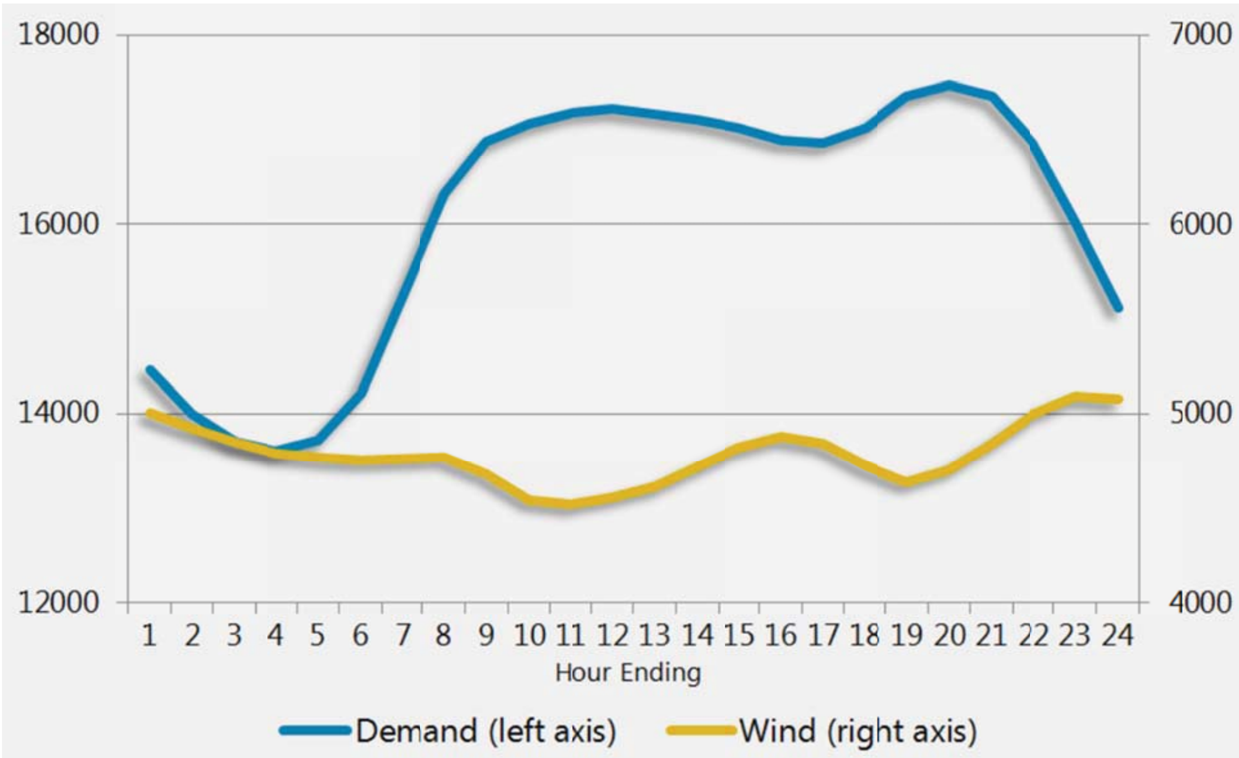


Figure 14. MIS North Average Hourly Demand and Wind 'roduction (MW) in 2016

Similarly, as shown in Figure 15, GRE's Expected Values hourly forecast demand curve for 2018-2032 follo vs a similar demand pattern, highlighting the benefit of shifting demand to overnig t hours to i crease demand for wind resources.[49] This is increasingly important now when prices for new wind resources are at their cheapes . As cited a ove, cost information from Xcel En rgy's most recent request for proposals for new wind show more than 30 proposals with costs below $22/M 'h.

---

[48] MISO Market Re orts, 2016 Historical Generation F el Mix and 2016 Historical Regional Forecast and Actual Load.
[49] Great River Energy's Response to CEO IR No. 1 (May 26, 2017).

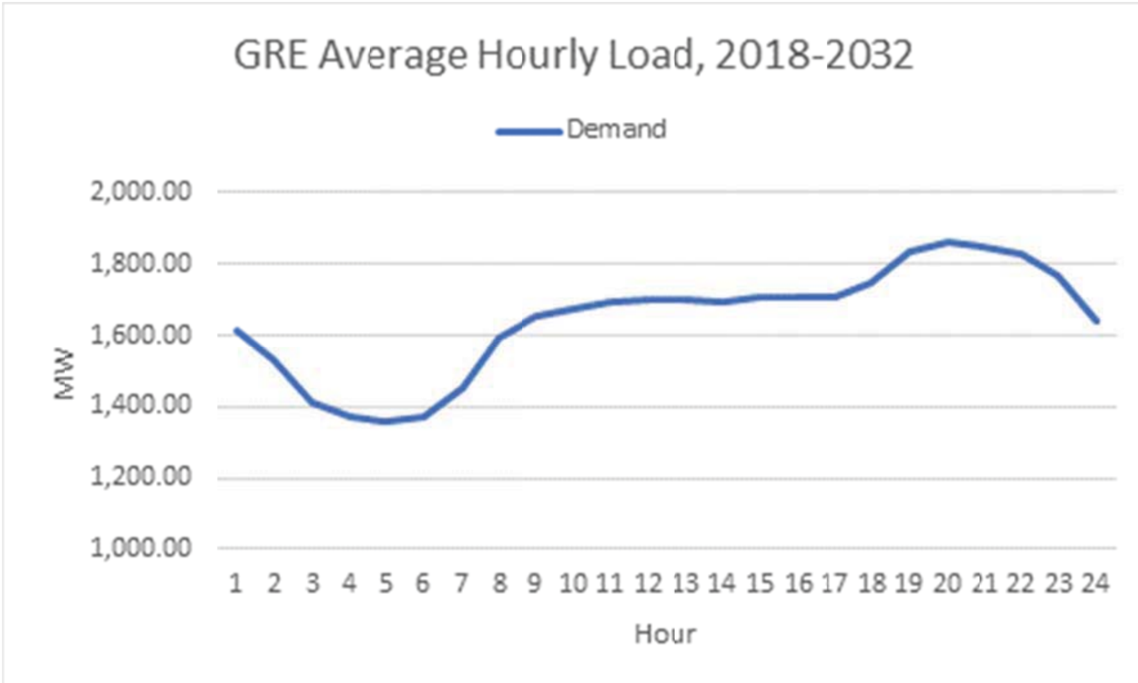


Figure 15. GRE Average Hourly Load 2018 – 2032

Furthermore, GRE's ETS off-peak water heater program has additional benefits compared to the peak shaving program because it shifts load throughout the entire year rather than on a few peak days and hours in the summer. Figure 16 shows that wind production from 2014-2016 was most prominent during the winter and winter shoulder months.[50] Thus, achieving load shifts year-round can capture times of the year when wind production is highest as well as from one time of the day to another.

[50] MISO Market Reports, Historical Hourly Wind Data, average of years 2014–2016. "Winter" = November through February. "Winter shoulder" = March, April, and October. "Summer shoulder" = May and September. "Summer" = June through August.

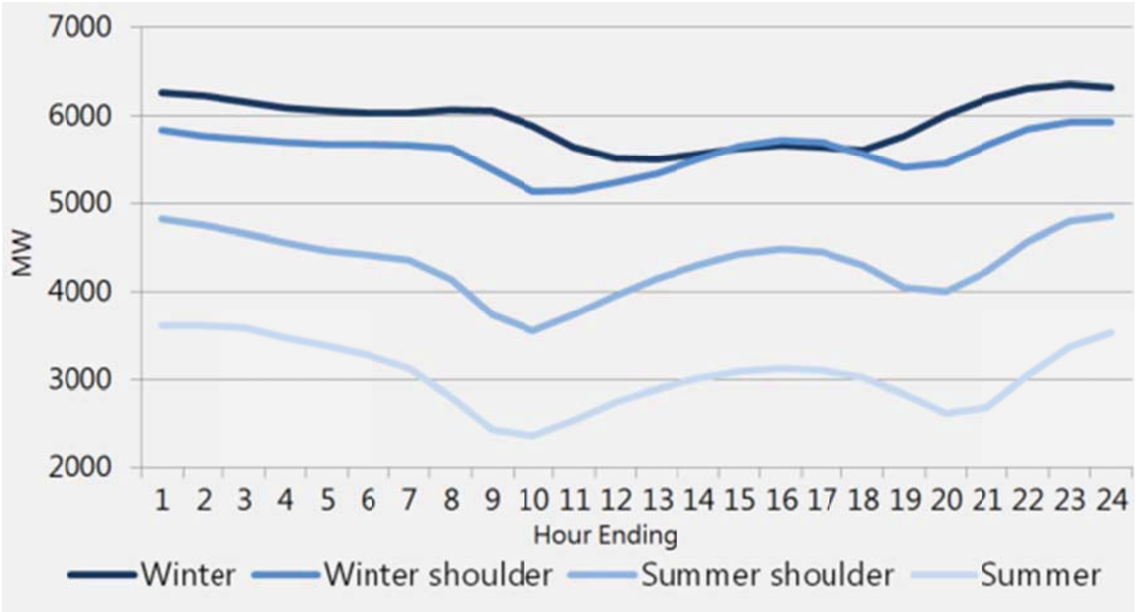


Figure 16. Average Hourly MISO Wind Production by Season for 2014-2016

Overall, GRE's ETS off-peak water heater program appears to be reducing peak costs year-round, providing cost-competitive options to customers who want to power their water heaters with electricity over other fuel sources, and driving long-term demand for wind resources. However, from a near-term carbon emissions perspective, GRE's current and forecasted generation portfolio does not result in net carbon reductions when powering water heaters with electricity instead of natural gas, and in fact results in significantly higher emissions per MMBtu of output as shown in Table 6. For comparison, we also provide the carbon emissions impact of powering electric water heaters on the mix of resources in MISO North's 2016 average generation portfolio.

Table 6. Water Heater Carbon Emission Comparison Summary

Water Heater CO2 Emissions Comparison			
Water Heating System	**CO_2 lbs per MMBtu input**[51]	**Heating System Efficiency**[52]	**CO_2 lbs per MMBtu output**

[51] Natural gas CO_2 lbs per MMBtu input taken from Energy Information Administration website: https://www.eia.gov/tools/faqs/faq.php?id=73&t=11. Electric CO_2 lbs per MMBtu input = (CO2 lbs/MWh) * (1 MWh/1,000 kWh) * (1 kWh/3,412 Btu) * (1,000,000 Btu/1 MMBtu).

[52] Heating system efficiencies found from manufacturer websites.

Natural Gas			
Atmospheric	117	61%	192
Power Damper	117	67%	175
Direct Power Vented	117	82%	143
Electric, using GRE's 2016 average CO_2 intensity values (1,607 lbs/MWh)[53]			
Marathon 85 gallon	471	93%	506
Marathon 105 gallon	471	95%	496
HTP 80 gallon	471	94%	501
Electric, using GRE's 2032 projected average CO_2 intensity (1,428 lbs/MWh)[54]			
Marathon 85 gallon	419	93%	450
Marathon 105 gallon	419	95%	441
HTP 80 gallon	419	94%	445
Electric, using MISO North's 2016 average CO_2 intensity (372 lbs/MWh)[55]			
Marathon 85 gallon	109	93%	117
Marathon 105 gallon	109	95%	115
HTP 80 gallon	109	94%	116

Therefore, as currently structured GRE's off-peak water heater program, while providing some benefits to advancing wind development as mentioned above, does not provide near-term progress on environmentally beneficial electrification. If the company hopes to expand or continue this program under the guise of environmentally beneficial electrification, it needs to significantly decarbonize its generation portfolio or provide a direct link between the electricity used to charge these water heaters and carbon-free generation resources. It can accomplish the latter by connecting GRE's renewable pricing options, such as Wellspring, with its off-peak ETS water heater program.

Regarding new technologies, GRE indicates that members of the Community Storage Initiative, of which GRE is a member and provides staff to chair, are "conducting a range of

---

[53] Great River Energy's Response to CEO IR No. 12, Table 3 (July 10, 2017).
[54] *Id.* Table 4.
[55] MISO Market Reports, Historical Generation Fuel Mix, 2016 available at https://www.misoenergy.org/Library/MarketReports/Pages/MarketReports.aspx.

innovative community programs, including grid-interactive water heating" among other efforts.[56] In addition, GRE states that it is piloting a small number of grid-interactive water heaters with one of its members. As GRE indicates:

> Such an approach would result in faster response times to ancillary services signals that are sent out by the grid operators and could reduce the carbon intensity of providing these services to the market. In addition to the regular control signal that turns a water heater on or off based on the time of day, grid-interactive water heaters also have a market signal that would indicate when to turn a water heater on or off in an effort to provide a means of balancing the system.[57]

CEOs fully support expanding the capabilities of GRE's ETS water heater program to include more dynamic, real-time control opportunities to best match use with loads on the system. This is also recognized as an important benefit by the Regulatory Assistance Project (RAP):

> According to the Hawaiian Electric Company's Integrated Demand Response Portfolio Plan, GIWH [grid-integrated water heaters] can be remotely turned on and off rapidly, making them a source of regulating reserves with the potential to counterbalance the intermittency of a given wind or solar power source.[58]

The same RAP report also highlighted the potential to integrate more wind and solar with this dynamic demand control:

> Control of these water heaters could provide the shaping and storage to integrate up to 100,000 MW of additional variable wind and solar energy in the US grid . . . . In 2013, Maui Electric Company curtailed approximately 18 percent of the wind energy available from local wind farms owing to system flexibility limitations. Hawaiian Electric estimated in 2014 that control of 6,300 electric water heaters in Maui would enable them to resolve the frequency excursion issues resulting from a 30-MW wind farm.[59]

---

[56] GRE 2018 IRP App. G.
[57] GRE 2018 IRP at 53.
[58] Lazar, Jim, *Teaching the "Duck" to Fly,* Regulatory Assistance Project, 23 (Feb. 2016) available at http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-teachingtheduck2-2016-feb-2.pdf.
[59] *Id.* at 20.

Unfortunately, GRE's plan does not detail how the company plans to expand its current water heater program in relation to how it interacts with the rest of its generation portfolio and resource mix, making it difficult to see the role this program will play in the company's operations moving forward. The CEOs inquired about this in IRs but look forward to seeing a more detailed response in GRE's reply comments.

CEOs recommend that, in reply comments in this docket, GRE provide a clear plan for how and when it will expand its off-peak ETS water heater program, and how and when it plans to incorporate grid-interactive features into its water heater program to maximize the dynamic benefits this resource can offer the system. We recommend that the Company provide this plan assuming existing MISO rules and tariffs, as well as recommend possible changes to MISO rules and tariffs that could expand the value of this program for the company, its members, and their customers. CEOs also recommend that, in reply comments in this docket, GRE indicate how and when it plans to make its off-peak ETS water heater program environmentally beneficial compared to other fuel sources.

VI. CONCLUSION

Clean Energy Organizations' comments demonstrate that GRE has not provided the Commission with a sufficient record on which to find that the 2018 IRP satisfies the public interest factors established in Minnesota rules. The Commission therefore does not have a record that could support acceptance of GRE's plan.

At a minimum, GRE must supplement the record on the following subjects CEOs have addressed in these initial comments:

- GRE must remedy deep flaws in its analysis of retiring the Coal Creek Station, including modeling the availability of power purchase agreements to bridge a 2020 retirement date;

addressing the perilous economics associated with Coal Creek's substantially rising fuel costs; utilizing a reference case that includes externalities and regulatory costs to evaluate plant retirement; and, modeling accurate costs of renewable resources and demand side alternatives;

- GRE must provide the analyses on energy efficiency potential that the Commission required in its Order on GRE's 2014 IRP;
- GRE must provide an energy forecast using a greater sample size and include the variables omitted from the forecast (or justify their omission);[BG1]
- GRE must provide plans to modify and expand "beneficial electrification" efforts such as its water heater program, to provide actual environmental benefits that result from a portfolio of low-carbon and renewable fuels.

Should GRE fail to provide the foregoing supplements to the record in its reply comments, CEOs request that the Commission reject the 2018 IRP.

Respectfully submitted,

/s/ Beth Goodpaster
Beth Goodpaster

Leigh Currie
Minnesota Center for Environmental Advocacy
26 E. Exchange Street, Ste. 206
St. Paul, MN 55101
(651) 287-4873

Attorneys for Fresh Energy, Minnesota Center for Environmental Advocacy, Sierra Club, and Wind on the Wires

Attachment A. Water Heater Life-Cycle Cost Summary[60]

Electric Water Heater Life-Cycle Cost Comparison		
Install Type	**Model/Electric Rate**	**Life-Cycle Cost of Unit**
	Marathon 4500 Watt Electric Water Heater (85 gallon)	
New Home Build	GRE Program Rate ($0.045/kWh with $400 rebate)	$3,910.93
	Connexus Rate ($0.1169/kWh)	$8,375.57
Retrofit	GRE Program Rate	$4,041.93
	Connexus Rate	$8,506.57
	Marathon 4500 Watt Electric Water Heater (105 gallon)	
New Home Build	GRE Program Rate	$4,157.38
	Connexus Rate	$8,536.44
Retrofit	GRE Program Rate	$4,288.38
	Connexus Rate	$8,667.44
	Westinghouse 4500 Watt Electric Water Heater (80 gallon)	
New Home Build	GRE Program Rate	$3,658.87
	Connexus Rate	$8,080.27
Retrofit	GRE Program Rate	$3,789.87
	Connexus Rate	$8,211.27

Natural Gas Water Heater Life-Cycle Cost Comparison		
Install Type	**Model/Electric Rate**	**Life-Cycle Cost of Unit**
	Rheem Residential Natural Gas Water Heater (50 gallon)	
New Home Build	Atmospheric	$3,906.03
	Atmospheric/Power Damper Vented	$4,024.50
	Condensing Power Direct Vent	$5,559.91
Retrofit	Atmospheric	$3,545.03
	Atmospheric/Power Damper Vented	$3,663.50
	Condensing Power Direct Vent	$5,869.91

Electric Heat Pump Water Heater Life-Cycle Cost Comparison		
Install Type	**Model**	**Life-Cycle Cost of Unit**
New Home Build	Rheem Prestige Hybrid (65 gallon)	$4,869.99

[60] Assumes a 13-year life for all water heater models analyzed.

	A.O. Smith Voltex Hybrid (50 gallon)	$4,575.07
Retrofit	Rheem Prestige Hybrid	$5,077.99
	A.O. Smith Voltex Hybrid	$4,783.07

Tankless Natural Gas Water Heater Life-Cycle Cost Comparison

Install Type	Model	Life-Cycle Cost of Unit
New Home Build	Rheem EcoSense Condensing Direct Vent	$4,494.56
Retrofit	Rheem EcoSense Condensing Direct Vent	$5,037.56