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July 1, 2016

The Honorable Jeanne M. Cochran
Administrative Law Judge
Office of Administrative Hearings
600 North Robert Street
P.O. Box 64620
St. Paul, MN 55164-0620

Re: *In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.*
MPUC Docket No. G-011/GP-15-895
OAH Docket No.68-2500-33191

Dear Judge Cochran:

Enclosed and e-filed in the above-referenced matter please find the PUBLIC and TRADE SECRET Testimony with Schedules of the Office of the Attorney General – Residential Utilities and Antitrust Division's witness Julie Urban.

The Highly-Sensitive Trade Secret version of this testimony is filed in Docket 16-315.

By copy of this letter all parties have been served. An Affidavit of Service is also enclosed.

Sincerely,

s/ Ryan Barlow

RYAN P. BARLOW
Assistant Attorney General

(651) 757-1473 (Voice)
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Enclosure

AFFIDAVIT OF SERVICE

Re: ***In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.***
MPUC Docket No. G-011/GP-15-895
OAH Docket No.68-2500-33191

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I hereby state that on July 1, 2016, I filed with eDockets the PUBLIC and TRADE SECRET ***Testimony with Schedules of the Office of the Attorney General – Residential Utilities and Antitrust Division's witness Julie Urban*** and served the same upon all parties listed on the attached service list by email, and/or United States Mail with postage prepaid, and deposited the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota.

s/ Judy Sigal
Judy Sigal

Subscribed and sworn to before me
this 1st day of July, 2016.

s/ Patricia Jotblad
Notary Public

My Commission expires: January 31, 2020.

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PUBLIC VERSION – TRADE SECRET AND HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED

BEFORE THE MINNESOTA OFFICE OF THE ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, Minnesota 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East
Suite 350
St. Paul, Minnesota 55101-2147

MPUC Docket No. G-011/GP-15-895
OAH Docket No.68-2500-33191

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project

DIRECT TESTIMONY AND EXHIBITS OF MINNESOTA OFFICE OF THE ATTORNEY GENERAL – ANTITRUST AND UTILITIES DIVISION

WITNESS:

JULIE URBAN

July 1, 2016

PUBLIC VERSION – TRADE SECRET AND HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED

CONTENTS

INTRODUCTION AND BACKGROUND

I. QUALIFICATIONS AND PURPOSE.

Q. Please state your name and business address.

A. My name is Julie A. Urban. My business address is Suite 1400, 445 Minnesota Street, St. Paul, Minnesota.

Q. By whom are you employed?

A. I am employed as a Utilities Economist with the Office of the Attorney General – Residential Utilities and Antitrust Division.

Q. What is your educational and professional background?

A. I have a Ph.D. in Economics from the University of New Mexico. I have also attended "Camp NARUC" and the "Demand Forecasting School" at the Institute of Public Utilities at Michigan State University. I joined the Residential Utilities and Antitrust Division of the Minnesota Attorney General ("OAG"), in August of 2015. Since that time, I wrote testimony and testified in the evidentiary hearing on cost of capital for the CenterPoint rate case, Docket G-008/GR-15-424. I also wrote comments on the cost of capital in the Gas Utility Infrastructure Cost Rider Petition by Xcel Energy, Docket G002/M-15-808.

Before coming to the OAG, I was employed at the Public Service Commission of Wisconsin ("PSCW") as an Advanced Economist. I worked for the PSCW for five years. In this position, I monitored transmission planning on the Mid-continental Grid and was co-chair of the Transmission Planning Work Group of the Organization of MISO States. In addition to monitoring transmission planning, I conducted need and economic analysis

on Applications for Certificates of Public Convenience and Necessity for transmission and generation projects.

Before working for the PSCW, I was an Associate Professor at the University of Wisconsin-Marinette Campus. I taught Macroeconomics, Microeconomics, Business and Economics Statistics, Money and Banking and Environmental Economics. Before teaching at the University of Wisconsin Marinette, I was an Assistant Professor at New Mexico Highlands where I taught Intermediate Microeconomics, Managerial Economics and Natural Resource Economics.

Prior to my academic positions, I was a senior gas supply planner for the Public Service Company of New Mexico where I conducted the daily load forecast and prepared the daily gas supply plan for the State of New Mexico. Prior to this position, I was an economic analyst for the City of Albuquerque where I did revenue forecasting. A summary of my educational and professional background is presented in Schedule JAU-1.

Q. Have you provided any other testimony before public utility commissions?

A. Yes. I testified on the cost of capital for the CenterPoint rate case, Docket G-008/GR-15-424. I testified on need and economic analysis for the Badger Coulee (Docket 5-CE-142), CapX (Docket 5-CE-136), Couderay-Osprey (Docket 4220-CE-178) and Pleasant Prairie-Zion (Docket 137-CE-161) transmission projects. I also testified on the economic analysis of the EPA Compliance project for the Weston 3 generation unit (Docket 6690-CE-193).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review Minnesota Energy Resources Corporation's ("MERC" or "the Company") request for approval and rider recovery of its Rochester Natural Gas Extension Project ("Rochester Project").

Q. Can you describe the Company's Rochester Natural Gas Extension Project?

A. The plan calls for the expansion of MERC's natural gas distribution system in and around the city of Rochester. The Company states that the expansion is necessary to meet current demand and expected growth in customer demand. This growth is driven by efforts to develop the Mayo Clinic into a Destination Medical Center. In addition to expanding MERC's distribution system, Northern Natural Gas ("NNG"), MERC's natural gas supplier, will be expanding capacity of its interstate pipeline in order to accommodate MERC's upgrade to its distribution system.

There are two phases to the expansion project. Phase I upgrades, which are already under construction, will enable MERC to balance the flow of natural gas on the low-pressure distribution system. The cost of Phase I is estimated at $5.6 million. Upon completion of Phase I, capacity for Rochester will be expanded by 10,500 Dth/day and 5,439 Dth/day will be available to 21 additional town border stations ("TBSs") in Southeast Minnesota.[1] The cost of Phase II includes $44 million for upgrades to MERC's distribution system and $58 to upgrade the NNG pipeline system.[2] Phase II provides the remaining incremental capacity of 34,500 Dth/day for Rochester, and the remaining 2,593 Dth/day for the other TBSs in Southeast Minnesota.

[1] Mead Direct, at 28.
[2] Lee Direct, at 4; Mead Direct, at 15.

Q. How is your testimony organized?

A. In Section II, I will discuss the standard by which I believe the Rochester Project should be reviewed. In Section III, I will describe the relevant facts for my review. In Section IV, I will provide my analysis of the reasonableness and prudence of MERC's proposal. In Section V, I will provide my analysis of MERC's proposal to allocate the costs of the Rochester Project. In Section VI, I will briefly discuss some other matters on which the Commission has requested information, including Rochester's goal to use 100% renewable energy, the availability of funding from other sources, and the eligibility of this project for recovery through a Natural Gas Extension Project rider. In Section VII, I will summarize and conclude my analysis.

II. THE STANDARD OF REVIEW FOR THE ROCHESTER PROJECT.

Q. Why is it necessary to discuss the standard of review for the Rochester Project?

A. It is important to discuss how to review the Rochester Project because MERC's request for an advanced determination of prudence is unusual. While there is a process for evaluating Certificate of Need ("CN") petitions, MERC is not required to obtain a CN for the Rochester Project and the rules and procedures for obtaining a CN are, generally, applied to electric generation and transmission projects.[3]

As a result, it is not entirely clear what MERC should be required to prove in order to obtain the advanced determination of prudence that it seeks. To inform my

[3] Minn. Stat. § 216B.243. The Rochester Project does not require a Certificate of Need because it is less than 50 miles in length, which is the statutory threshold for a Large Energy Facility. Minn. Stat. § 216B.2421, subd. 2(5).

understanding of how to review MERC's proposal, I began by reviewing MERC's testimony to clarify what, exactly, MERC has asked the Commission to do.

Q. What determinations has MERC requested?

A. It appears that MERC has asked the Commission for three determinations:

First, MERC asks the Commission to determine that the Rochester project is "reasonable and that MERC took a prudent approach to undertake the Project."[4] I interpret this as a request for an advanced determination of the prudence of the Rochester Project, which would likely carry with it a presumption of cost recovery at the level of costs estimated by the Company in this case—approximately $107 million.

Second, MERC asks the Commission to determine that 33% of the costs of the project may be recovered through a Natural Gas Extension Project Rider pursuant to Minnesota Statutes section 216B.1638. I view this question as separate from the first question, because the Commission could approve of the Rochester Project, but require MERC to recover the costs of the project through base rates rather than an NGEP Rider.

Third, MERC asks the Commission to determine that MERC's proposed allocation of across MERC customers and across NNG-PGA customer classes is reasonable.

[4] Lee Direct, at 39.

Q. Has the Commission indicated any specific matters that should be addressed in this case?

A. Yes. In its Notice of and Order for Hearing, the Commission requested that the Office of Administrative Hearings include three questions in the scope of this proceeding:[5]

1. Are the Rochester Project investments prudent, reasonable, and necessary to provide service to MERC's Rochester service area, taking into account the City of Rochester's announced goal of using 100% renewable energy by 2031?

2. Is it reasonable to recover the Rochester Project costs from all of MERC's ratepayers?

    a. If so, on what basis;

    b. If not, what other allocation method would be more reasonable?

3. What other funds may be available to cover the project costs?

The first and second questions respond directly to two of MERC's requests, while the third seeks additional analysis on a specific point.

Q. Is there any other guidance on how to review advanced determinations of prudence?

A. Yes. In other contexts, utilities use the CN process to obtain advanced determinations of prudence from the Commission. While MERC does not need to obtain a CN for the Rochester Project, the CN process can still provide useful guidance on what analysis will be useful in this case. There are statutory criteria for a CN, as well as Rules promulgated by the Commission.

[5] Notice of and Order for Hearing, *In the Matter of a Petition by Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for Its Rochester Natural Gas Extension Project*, Docket No. G-011/M-15-895, at 3 (Feb. 8, 2016).

Q. What are the statutory criteria for an advanced determination of prudence under a CN?

A. Minnesota Statutes section 216B.243 requires the Commission to consider twelve factors in evaluating a Large Energy Facility, some of which are relevant to the Rochester Project:

(1) the accuracy of the long-range energy demand forecasts on which the necessity for the facility is based;

(2) the effect of existing or possible energy conservation programs;

(3) the relationship of the proposed facility to overall state energy needs;

(4) promotional activities that may have given rise to the demand for this facility;

(5) the benefits of the facility, including its uses to protect or enhance environmental quality, and to increase reliability of energy supply;

(6) possible alternatives for satisfying the energy demand;

(7) the policies, rules, and regulations of other state and federal agencies and local governments; and,

(8) any feasible combination of energy conservation improvements that can (i) replace part or all of the facility or (ii) compete with it economically.

The remaining factors are generally associated with electric facilities and do not appear to be relevant here.

Q. What are the criteria for a CN in the Commission's Rules?

A. The Commission promulgated Minnesota Rules part 7851.0120 to provide criteria for evaluating Certificates of Need for natural gas pipelines. The rules generally track the statutory criteria, but are organized into four general concepts:

First, the Commission must determine whether denial would adversely affect the future adequacy, reliability, or efficiency of energy supply, considering (1) the accuracy of the forecast; (2) the effect of conservation programs; (3) the effects of promotional practices by the utility; (4) the ability of current facilities to meet future demand; and (5) the effect of the proposed facility in making efficient use of resources.[6]

Second, the Commission must determine whether a more reasonable and prudent alternative exists, considering (1) the appropriateness of the size, type, and timing of the proposed facility; (2) the costs of the proposed facility and the cost of the energy to be supplied compared to reasonable alternatives; (3) the effects of the proposed facility upon the natural and socioeconomic environments compared to alternatives; and (4) the expected reliability of the proposed facility compared to alternatives.[7]

Third, the Commission must determine whether "the consequences to society of granting the certificate of need are more favorable than the consequences of denying," considering (1) the relationship of the facility to state energy needs; (2) the effects of the proposal on natural and socioeconomic environments compared to the effect of not building it; (3) the effects of the proposed facility in inducing future development; and (4) the socially beneficial uses of the output of the proposed facility, including its use in protecting or enhancing environmental quality.[8]

[6] Minn. Rules part 7851.0120(A).
[7] Minn. Rules part 7851.0120(B).
[8] Minn. Rules part 7851.0120(C).

Fourth, the Commission must determine whether the proposed facility would fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.[9]

Q. Do you recommend that the Commission strictly apply the CN criteria or rules in this case?

A. No. The legislature and the Commission have indicated that the CN process is only required for some Large Energy Facilities, and according to that definition the Rochester Project does not require a CN. I do, however, believe that the CN criteria and rules can provide guidance on the analysis used to review the Rochester Project.

Q. Based on this guidance, how should the Commission review MERC's request for an advanced determination of prudence for the Rochester Project?

A. The ultimate question that must be answered in this proceeding is whether the Rochester Project is prudent, and whether including its costs in MERC's rates would result in rates that are just and reasonable.[10] After reviewing these resources, I believe that determining whether the Rochester Project is prudent and reasonable should focus on three issues:

First, has MERC demonstrated that there is a need for infrastructure investment in the Rochester area? This inquiry will focus on MERC's long-range energy forecasting, as well as the demand day that provides the foundation of that forecasting.

Second, is the Rochester Project a reasonable way to address the need that is demonstrated by the forecasting?

Third, and related to the second issue, is the Rochester Project reasonable compared to other alternatives that MERC considered or should have considered? Or, in

[9] Minn. Rules part 7851.0120(D).
[10] Minn. Stat. § 216B.03.

other words, has MERC acted prudently in deciding to proceed with the Rochester Project as proposed, as compared to other alternatives?

In Section III, I will discuss the facts that are relevant to these questions, and in Section IV I will provide my analysis on the issues.

II. BACKGROUND FACTS.

Q. What will you address in this section?

A. In this Section I will discuss MERC's claims as to the current and future demand for natural gas in the Rochester region, and a description of MERC's Request for Proposals ("RFP") as well as the responses that MERC received to its RFP.

A. MERC STATES THAT INFRASTRUCTURE INVESTMENTS ARE REQUIRED BECAUSE IT IS UNABLE TO MEET CURRENT OR FUTURE DEMAND FOR NATURAL GAS.

Q. Why does MERC state that infrastructure investments for the Rochester Project are necessary?

A. MERC states that it must invest in the Rochester Project because it cannot satisfy the current or future demand for natural gas. According to MERC, the demand for natural gas exceeded the Company's available supply on a specific day during the Polar Vortex —January 6, 2014.[11] On that day, MERC exceeded its contracted firm capacity from interstate pipelines.[12] Discovery by the OAG indicates that on January 6, 2014, MERC curtailed its large volume interruptible customers, but chose not to curtail its small volume interruptible customers.[13]

[11] Mead Direct, at 6.
[12] *Id.*
[13] MERC's response to OAG IR 134, attached as Schedule JAU-2.

In addition, MERC states that it is generally operating without sufficient reserves of contracted natural gas supply.

Q. How are firm capacity needs determined?

A. Firm capacity needs are based on the Design Day requirement. The Design Day requirement is based on the coldest adjusted heating degree day ("AHDD") in 20 years. Simply put, the Design Day calculation is an attempt to project the amount of firm customer demand on the coldest day that a utility could reasonably expect to face, given the prior 20 years of weather. A utility's Design Day requirement informs its needs for firm gas supply.

Q. How did MERC determine its Design Day requirements?

A. A description of how to estimate firm capacity need or design day requirement is provided in Attachment C of the Compliance Filing for Demand Entitlement.[14] Ordinary Least Squares ("OLS") linear regressions corrected for autocorrelation are used to estimate the parameters of the prediction equations for each border station. The throughput volumes (the dependent variable) and AHDDs (the explanatory variable) used to estimate the regression equations for each border station, are based on the past last three winters. Once the predictive equations are determined, the AHDD based on the coldest day in twenty years is plugged into the estimated regression equation to determine the Design Day throughput volume. The coldest day for Rochester weather occurred on February 2, 1996 with an average daily temperature of -27 degrees Fahrenheit. Next, the

[14] Compliance Filing – Update to Demand Entitlement, *In the Matter of the Petition for Minnesota Energy Resources Corporation – Northern Natural Gas for Approval of a Change in Demand Entitlement*, Docket No. G011/M-15-723, Attachment C, at 6–9 (Nov. 2, 2015).

estimated volumes are adjusted for risk to attain a confidence level of 97.5 percent. This amount is the Peak Day volume estimate.

Q. What is MERC's current Design Day for the Rochester area?

A. MERC states that the current Design Day for the Rochester area for the 2016/2017 heating season is 60,869 Dth/Day.[15] In comparison, MERC's current firm capacity from NNG for the Rochester area is 55,169 Dth/Day, for a reserve margin of -9.36 percent.

Q. What is the meaning of the reserve margin?

A. The reserve margin is computed by taking the difference between current firm capacity and the Design Day requirement and dividing that amount by the design day amount. It provides the percentage of excess reserve over (or below) what is predicted to be required. In other words, the reserve margin is how much natural gas capacity MERC currently has available compared to how much natural gas capacity is necessary to service its customers on the Design Day forecast.

Q. Does MERC project that its Design Day requirements will grow in the future?

A. Yes. In addition to identifying current problems, MERC states that it expects the need for natural gas in the Rochester region will grow in the future.

Q. How did the Company forecast growth in its Demand Day?

A. The forecast for Rochester was conducted by revenue class with monthly historical billed and customer count data. OLS was used to estimate the forecast using monthly binaries, time trend heating degree days ("HDD") and economic and demographic variables. The models also included some seasonal and autoregressive components where necessary to correct for seasonality and serial correlation. The OLS estimation was based on historical

[15] MERC's Response to DOC IR 15, attachment Rochester Design Peak Day Analysis Revised with Rochester Weather.xlsx, attached as Schedule JAU-3.

data from 2007 through July 2015. A list of models for each rate class, including the list of independent variables for each model, is provided in a table on page 77 of MERC's Petition.[16]

Q. What sales growth rate is applied to determine future capacity need?

A. MERC is proposing an increase in firm capacity with NNG. Firm capacity includes Residential, Small Commercial and Industrial (SC&I) and Large Commercial and Industrial (LC&I). The average annual growth in firm or retail customer demand based on the original sales forecast was 1.6 percent. MERC later revised the growth rate to 1.5 percent in response to a request by the Department to use heating degree data based on Rochester weather rather than the virtual weather station used in the original petition. The Design Day peak demand for each subsequent year is increased by an average annual growth rate of 1.5 percent based on the Company's forecasted growth in capacity demand.

Q. What will be the impact on the reserve margin for Rochester over time given the Company's forecast?

A. The impact on the reserve margin is presented in Table 1 below.

[16] Initial Petition, *In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project*, Docket No. G011/GP-15-895, at 77 (Oct. 26, 2015) [hereinafter "Petition"].

Table 1
Reserve Margin Impacts[17]

Winter Period	Rochester Design Day	Rochester Capacity	MERC Reserve Margin
2015/2016	59,969	55,169	-8.00%
2016/2017	60,869	55,169	-9.36%
2017/2018	61,782	55,169	-10.70%
2018/2019	62,709	55,169	-12.02%
2019/2020	63,649	55,169	-13.32%
2020/2021	64,604	55,169	-14.60%
2021/2022	65,573	55,169	-15.87%
2022/2023	66,557	55,169	-17.11%
2023/2024	67,555	55,169	-18.33%
2024/2025	68,568	55,169	-19.54%
2025/2026	69,597	55,169	-20.73%
2026/2027	70,641	55,169	-21.90%
2027/2028	71,701	55,169	-23.06%
2028/2029	72,776	55,169	-24.19%
2029/2030	73,868	55,169	-25.31%
2030/2031	74,976	55,169	-26.42%
2031/2032	76,100	55,169	-27.50%
2032/2033	77,242	55,169	-28.58%
2033/2034	78,400	55,169	-29.63%
2034/2035	79,576	55,169	-30.67%
2035/2036	80,770	55,169	-31.70%
2036/2037	81,982	55,169	-32.71%
2037/2038	83,211	55,169	-33.70%
2038/2039	84,460	55,169	-34.68%
2039/2040	85,726	55,169	-35.65%

MERC's forecast indicates that Rochester currently has a negative reserve margin and that the shortage of firm capacity will increase as capacity demand increases over time. I will address several concerns with MERC's forecast in Section IV.

[17] The data for Table 1 was drawn from MERC's Response to DOC IR 15, attachment Rochester Design Peak Day Analysis Revised with Rochester Weather.xlsx, attached as Schedule JAU-3.

Q. What is the main barrier to meeting demand for natural gas?

A. According to MERC Witness Ms. Lee, "[T]he main barrier for MERC to continue to meet its design day requirements for customers in the Rochester area is the limited level of interstate pipeline capacity reserve that currently exists."[18] To address this problem, MERC designed and issued an RFP to increase the supply of natural gas in the Rochester area.

B. MERC'S REQUEST FOR PROPOSALS AND THE RESPONSES.

Q. What will you discuss in this section?

A. In this section, I will address MERC's RFP and the responses to the RFP. I will first describe the RFP that MERC issued, and then discuss the responses from Northern Border Pipeline and Twin Eagle Resource Management, LLC. Then, because of its complexity, I will discuss the response from NNG separately.

Q. Is all of the information in this section publicly available?

A. No. I note at the outset that some of the information I will discuss in this section is marked as various levels of Trade Secret. In particular, the responses to the RFP are marked as Highly Sensitive Trade Secret, which is a designation intended to ensure that potential competitors or future bidders do not obtain access to bids from other parties.

1. MERC's RFP.

Q. Did MERC provide the RFP and responses to the RFP in its Petition or Testimony?

A. No. The OAG had to obtain the RFP through the discovery process. While I am sensitive to MERC's concerns regarding the confidentiality of the RFP, I believe that MERC should have provided this information in its initial filing. It is unclear to me how

[18] Lee Direct, at 12.

the Commission could be expected to approve of MERC's proposal without a thorough understanding of how MERC's RFP was designed and what responses it received. In order to make sure that the Commission has this information, I will undertake to describe the RFP and the responses in my testimony.

Q. Can you describe the Request for Proposals that MERC issued?

A. Yes. On December 31, 2014, MERC issued a Request for Proposal seeking bids to "provide transmission pressure natural gas to the Rochester Minnesota area."[19] In the RFP, MERC sought bids for two different options to increase natural gas service.

Option 1 was to construct a pipeline to inter-connect with a new MERC TBS on the northwest side of Rochester for a total capacity of 100,000 Dth/day of firm capacity at 600 psig, to be paid for over a minimum of 25 years. Option 2 was to work with the existing supplier, NNG, to connect to its system and existing MERC TBSs and increase the capacity available by 45,000 Dth/day.

Q. How many responses did MERC receive to the RFP?

A. MERC received responses from three companies—NNG, Northern Border Pipeline, and Twin Eagle Resource Management, LLC.[20] The OAG has obtained the Highly Sensitive Trade Secret responses to MERC's RFP, and they are attached as Schedule JAU–5, which MERC has marked Highly Sensitive Trade Secret to ensure that competitors do not gain access to competing bids. I will first describe the Northern Border and Twin Eagle proposals.

[19] MERC's RFP is attached as Schedule JAU-4.
[20] Sexton Direct, at 41.

B. Northern Border and Twin Eagles Proposals.

Q. Can you describe the proposal by Northern Border Pipeline?

A. Yes. **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS]

Q. Can you describe the Twin Eagles proposal?

A. Yes. **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS].

2. Northern Natural Gas Proposals.

Q. Can you describe NNG's proposal?

A. Yes. **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS]

3. The Precedent Agreement with NNG.

Q. Which proposal did MERC accept?

A. MERC negotiated with NNG using **[HIGHLY SENSITIVE TRADE SECRET BEGINS] [HIGHLY SENSITIVE TRADE SECRET ENDS]**. That negotiation resulted in a Precedent Agreement which, to my knowledge, MERC has not filed in this proceeding. To ensure that the record is complete, I have attached it as Trade Secret Schedule JAU-7.[21] According to MERC, the agreement will provide approximately 100,000 Dth/day to the Rochester area at a construction cost of "a

[21] MERC's precedent agreement is marked as trade secret and is attached as Schedule JAU-7.

little under $60 million."[22] The agreement will increase natural gas deliveries at existing TBS 1D, and also deliver gas to a new TBS which will replace existing TBS 1B.[23] The pressure at the new TBS will be 500 psig, and will be 450 psig at TBS 1D.[24] The agreement will also allow MERC to further expand its capacity in the future, and to move up to 20% of the available capacity to other TBSs in the Rochester area "on most days."[25]

In addition, [**TRADE SECRET BEGINS]**

[TRADE SECRET ENDS]

Q. How did MERC seek approval for its preferred option?

A. MERC sought approval from the Commission to proceed with the Rochester plan by filing a Petition in this proceeding on October 26, 2015. In response to the Company's petition, the OAG recommended that the Commission refer this matter to the Office of Administrative Hearings for a contested case proceeding. The Commission ultimately agreed and required MERC to file direct testimony regarding its request. I have reviewed

[22] Mead Direct, at 13.
[23] Mead Direct, at 16.
[24] Mead Direct, at 16.
[25] Mead Direct, at 22. In a response to a Department IR, MERC stated that "[t]he use of the 20% at alternate points would be on a secondary basis . . . [that] could be limited by Force Majeure, but also by group or point constraints outside of a Force Majeure." MERC's Response to DOC IR 25, attached as Schedule JAU-8.

MERC's testimony and summarized the important facts above, and will now proceed to provide my analysis.

ANALYSIS

III. REVIEW OF THE PRUDENCE AND REASONABLENESS OF THE ROCHESTER PROJECT.

Q. What is the purpose of this section of your Testimony?

A. The primary goal of my testimony is to review whether the Rochester Project is a prudent and reasonable way for MERC to meet the demand for natural gas. As I discussed above, while performing this analysis I kept three questions in mind: First, has MERC demonstrated that there is a need for infrastructure investment in the Rochester area? Second, is the Rochester Project a reasonable way to address any need that is demonstrated by the forecasting? Third, and related to the second issue, is the Rochester Project reasonable compared to other alternatives that MERC considered or should have considered?

After completing my analysis, I conclude that MERC has not satisfactorily answered any of these questions. I will address each separate inquiry in turn. In Section A, I will discuss the problems with MERC's forecast of the demand for natural gas. In Section B, I will discuss specific reasons that the Precedent Agreement does not propose a reasonable solution for any existing demand for natural gas. In Section C and D, I will discuss my concerns with MERC's handling of the RFP and its failure to consider some alternatives. In Section E, I will present my conclusion and recommendations regarding

the prudence and reasonableness of MERC's proposal for the Rochester Project, as contained in the Precedent Agreement.

A. MERC'S FORECASTING METHODOLOGY IS FLAWED.

Q. Do you have any concerns with the Company's forecast?

A. Yes. My analysis indicates that MERC's forecast has significant problems, which means that its projections of future natural gas demand are not reliable. This is a significant problem because the RFP was designed, and the Precedent Agreement was entered into, explicitly to ensure that MERC would have sufficient supply to meet the amount of demand it forecasts in the 2040s. As a result, if the forecasts are flawed, then MERC has designed its RFP and the Precedent Agreement to obtain more natural gas that is reasonable.

I have five distinct problems the Company's sales forecast: 1) use of virtual weather station; 2) regressions based on only eight years of data; 3) the estimation of residential and SC&I average customer use; 4) the use of "Priori Information" in the customer count models for residential and SC&I; and 5) growth assumptions based primarily on the Mayo Clinic Expansion and the Destination Medical Center ("DMC") Initiative.

1. Adjustment to Rochester Weather

Q. What is your first concern with the sales forecasting?

A. The first concern is that the original sales forecasts included a weather variable based on a "virtual weather station" composed of locations throughout the state rather than the Rochester weather. The Department of Commerce ("DOC") requested that the sales

forecasts be revised using weather specific to Rochester.[26] This adjustment resulted in an overall decline in projected average annual growth in retail sales (excluding interruptible and transport) from 1.6% to 1.5%.[27]

2. Regressions based on only eight years of data.

Q. What is your second concern with the sales forecasting?

A. I have concerns with a regression analysis based on so few years of historical data. As stated above, the historical data used in MERC's forecasting analysis is limited to eight years. MERC does not have reliable data prior to 2007, when MERC was purchased by Integrys. For a full discussion of the legacy data available to MERC, see MERC's response to OAG IR 155.[28] Table 3 presents historical usage by retail customer class.

Table 2[29]

Historical Rochester Annual Gas Consumption by Ultimate Consumers					
Calendar Sales: Units MCF			Revised with Rochester weather		
		Small	Large		Percentage
Year	Residential	Commercial	Commercial	Total	Change
2007	3,365,431	83,859	1,469,313	4,918,603	
2008	3,705,225	95,485	1,613,473	5,414,183	10.1%
2009	3,526,467	101,010	1,499,955	5,127,432	-5.3%
2010	3,374,777	99,720	1,426,417	4,900,914	-4.4%
2011	3,464,782	122,001	1,548,654	5,135,437	4.8%
2012	2,861,123	84,553	1,346,091	4,291,767	-16.4%
2013	3,824,179	147,097	1,760,247	5,731,523	33.5%
2014	4,238,355	190,538	1,971,412	6,400,305	11.7%
2015	3,191,334	117,200	1,529,603	4,838,137	-24.4%
Average Annual Percentage Change from 2007 and 2015					(0.00204)

[26] MERC's Response to DOC IR 15, attachment Rochester Design Peak Day Analysis Revised with Rochester Weather.xlsx, attached as Schedule JAU-3.
[27] Clabots Direct, at 7.
[28] MERC's Response to OAG IR 155 (response to question 3 on page 2), attached as Schedule JAU-9.
[29] MERC's response to OAG IR 155.6 (Rochester Revised with Rochester Weather and historical data-2.xlsx, Tab Subp.3A-Annual Gas Consumption), attached as Schedule JAU-10.

One can see by looking at the historical data in Table 3, that even when using weather normalized data, there are substantial swings in total sales from year to year with no discernable trend. The year 2014 was extremely cold which is why there is a substantial increase in sales between 2013 and 2014 and a steep decline from 2014 to 2015, despite the data being weather normalized. There could be a problem with the weather normalization methodology.[30] Using July and August to calculate Base Load Sales may not be appropriate for a pipeline since there could be transport customers that have high demand during these months to meet air conditioning needs. In response to DOC IR 13, MERC reports that it has transport customers that are weather sensitive.[31] For example, MERC provides transport service to two natural gas generating units for Rochester Public Utility and to the Franklin Heating Station.[32] Nonetheless, there is no historical basis for the forecast of 1.5 percent average annual growth.

3. Estimation of Residential Average Use

Q. What is your third concern with the sales forecasting?

A. Another concern is the model used to estimate Residential Average Use. Unlike the small commercial and industrial average use model, the residential average use model does not include a time trend variable. This may be a problem in that one might expect that the average residential average use would also be trending downward over time just as it is in small commercial and industrial use. Including a time trend variable in the regression analysis will allow us to discern whether this is the case and if the impact of the downward trend is significant. Through an information request, I asked that a time

[30] Direct Testimony of Mr. Harry W. John, *In the Matter of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G011/GR-15-736, at 20 (Sept. 30, 2015).
[31] MERC's Response to DOC IR 13, attached as Schedule JAU-11.
[32] MERC's Responses to OAG IR 107 and 123, attached as Schedules JAU-12 and JAU-13.

trend variable be included in the equation estimating residential use per customer. The results indicate that the time trend variable is negative and highly significant with a p-value of 0.00 percent.[33] Including a time trend variable in the model estimating residential use per customer results in a 1.34 percent increase in sales versus the 2.00 percent increase filed in the Petition based on the original estimation procedure.[34]

4. Use of "Priori Information"

Q. What is your fourth concern with the sales forecasting?

A. Another major concern is that MERC "chose models that were on the robust side of valid statistical models to incorporate the growth of the expected impact from the Mayo Clinic expansion" for the Rochester Residential and SC&I forecast models.[35] The Rochester Residential and Small C&I customer count models are based on "Priori Information." This means that the models are based not only on recent historical growth but on the expectations of future growth based on information from MERC's Gas Planning Committee as well as other MERC staff.[36] As one can see in Table 4, the forecasted average annual growth rate in sales of 2.15 percent for the residential class is well over twice the historical average annual growth rate of 0.81 percent. Looking at Table 5, the big percentage growth rates observed in 2010, 2012 and 2013 were the result of customers moving from the LC&I customer class to the SC&I customer class.[37] So it is

[33] MERC's Response to OAG IR 155.7-2, attached as Schedule JAU-14. The p-value is widely used in statistical hypothesis testing or to measure the statistical significance of the explanatory variable. The lower the p-value the less likely that residential average use has not been trending downward.
[34] MERC's Response to OAG IR 155.7, Attachment OAG-155-7 Residential UPC Supplemental Response.xlsx, attached as Schedule JAU-15.
[35] MERC's Response to OAG IR 155 (question 7), attached as Schedule JAU-9.
[36] Petition, at 77.
[37] MERC's Responses to DOC IRs 6–8, attached as Schedule JAU-16.

difficult to tell from so few years of data whether the forecasted growth rate for the SC&I class is reasonable.

Table 3[38]

	Historical Growth				Forecasted Growth	
	Number of Residential	Percentage			Number of Residential	Percentage
Year	Customers	Change		Year	Customers	Change
2007	38,482			2015	41,010	0.88%
2008	38,838	0.93%		2016	41,554	1.33%
2009	39,180	0.88%		2017	42,191	1.53%
2010	39,490	0.79%		2018	42,912	1.71%
2011	39,622	0.33%		2019	43,710	1.86%
2012	39,883	0.66%		2020	44,579	1.99%
2013	40,288	1.02%		2021	45,515	2.10%
2014	40,651	0.90%		2022	46,513	2.19%
				2023	47,569	2.27%
				2024	48,679	2.33%
				2025	49,840	2.39%
Average Annual Percentage Growth		0.81%		Average Annual Percentage Growth		2.15%

Table 4[39]

	Historical Growth				Forecasted Growth	Percentag
	Number of	Percentage			Number of	
Year	SC&I Customers	Change		Year	SC&I Customers	Change
2007	1,044			2015	1,412	2.24%
2008	1,054	0.96%		2016	1,437	1.77%
2009	1,054	0.00%		2017	1,462	1.74%
2010	1,168	10.82%		2018	1,493	2.12%
2011	1,197	2.48%		2019	1,526	2.21%
2012	1,313	9.69%		2020	1,561	2.29%
2013	1,370	4.34%		2021	1,598	2.37%
2014	1,381	0.80%		2022	1,632	2.13%
				2023	1,674	2.57%
				2024	1,714	2.39%
				2025	1,754	2.33%
Average Annual Percentage Growth		4.61%		Average Annual Percentage Growth		2.42%

[38] MERC Reply Comments, C13 Residential Customer Forecast Model.xls (Dec. 7, 2015).
[39] *Id.*

5. Mayo Clinic Expansion and the Destination Medical Center

Q. What is your concern related to the DMC?

A. My final concern is that the Mayo Clinic Expansion and that the Development Plan for the DMC may not result in the kind of growth necessary to justify such a large expansion in capacity. The Company's sales forecast is based on the Mayo Clinic Expansion and the DMC Initiative. The Company points out in its petition: "The assumptions made on Rochester Residential and SC&I are primarily based on the Mayo Clinic expansion, and the economic growth in the Rochester area. These assumptions do have significant impact on the forecasts."[40]

Q. What is the DMC Initiative?

A. State financial assistance for infrastructure development may be available to the City of Rochester under the DMC statute. The availability of state financial assistance is contingent on the level of expenditures made by the Mayo Clinic and other private entities for construction projects. Two hundred million dollars of private investment is required before the public money is made available. As of April 1, 2016 approximately $150 million had been invested so the eligibility threshold for state assistance has not yet been achieved.[41] In response to an information request regarding any increase in natural gas usage within the DMC Development District, MERC stated "…no customer within the DMC Development District indicated any definitive plans regarding anticipated future natural gas usage."[42]

[40] Petition, at 78.
[41] Lee Direct, at 35–36.
[42] MERC's response to OAG IR No. 125, attached as Schedule JAU-17.

This may be additionally problematic because it does not appear that MERC has had extensive contact with the DMC. In the hopes of learning more about DMC's relationship with the Company, the OAG reached out to the DMC directly. The OAG also requested that MERC provide copies and descriptions of all its communications to the DMC. In its response, MERC indicated that its first contact with the DMC was in February, 2016, nearly four months after it filed its Initial Petition in this proceeding.[43] MERC states that part of the reason it expects such growth in the Rochester area is the DMC, but it does not appear as if the Company has been in close contact with the DMC about that growth.

6. Conclusion regarding MERC's sales forecast.

Q. What is your final conclusion concerning the Company's forecast that is used to justify its capacity expansion request?

A. I am uncomfortable with the Company's forecast of 1.5 percent annual growth in Rochester capacity demand. For all the reasons explained above I think that there are weaknesses in the forecast methodology and there is no historical evidence to substantiate the forecasted amount of growth. In addition, there is a lot of uncertainty concerning the Mayo Clinic Expansion and that the Development Plan for the DMC which is the basis for the capacity expansion plan. Although there is immediate need to expand Rochester capacity, given the uncertainty regarding DMC plans, the significant role of DMC-related growth in the forecast, and the enormous investment being asked of ratepayers for this project, it is important to proceed with caution especially in regard to the size of the capacity expansion.

[43] MERC's response to OAG IR 199, attached as Schedule JAU-18.

Q. What results will the Company's forecast have on the reserve margin for Rochester over time?

A. The results are presented in Table 5 below.

Table 5[44]
Rochester Staging Plan (45,000 Dth/Day)

Winter Period	Rochester Design Day	Capacity 1D	Capacity 1B	Capacity New TBS	Rochester Capacity	MERC Reserve Margin
2015/2016	59,969	36,707	18,462	0	55,169	-8.00%
2016/2017	60,869	36,707	18,462	0	55,169	-9.36%
2017/2018	61,782	36,707	18,462	0	55,169	-10.70%
2018/2019	62,709	47,207	18,462	0	65,669	4.72%
2019/2020	63,649	40,707	18,462	41,000	100,169	57.38%
2020/2021	64,604	40,707	18,462	41,000	100,169	55.05%
2021/2022	65,573	40,707	18,462	41,000	100,169	52.76%
2022/2023	66,557	40,707	18,462	41,000	100,169	50.50%
2023/2024	67,555	40,707	18,462	41,000	100,169	48.28%
2024/2025	68,568	40,707	0	59,462	100,169	46.09%
2025/2026	69,597	40,707	0	59,462	100,169	43.93%
2026/2027	70,641	40,707	0	59,462	100,169	41.80%
2027/2028	71,701	40,707	0	59,462	100,169	39.70%
2028/2029	72,776	40,707	0	59,462	100,169	37.64%
2029/2030	73,868	40,707	0	59,462	100,169	35.61%
2030/2031	74,976	40,707	0	59,462	100,169	33.60%
2031/2032	76,100	40,707	0	59,462	100,169	31.63%
2032/2033	77,242	40,707	0	59,462	100,169	29.68%
2033/2034	78,400	40,707	0	59,462	100,169	27.77%
2034/2035	79,576	40,707	0	59,462	100,169	25.88%
2035/2036	80,770	40,707	0	59,462	100,169	24.02%
2036/2037	81,982	40,707	0	59,462	100,169	22.18%
2037/2038	83,211	40,707	0	59,462	100,169	20.38%
2038/2039	84,460	40,707	0	59,462	100,169	18.60%
2039/2040	85,726	40,707	0	59,462	100,169	16.85%

Q. Are you concerned that the reserve margin for Rochester is negative until 2018?

A. No. Although there is currently a need for additional capacity in Rochester, based on the design peak day, additional capacity is not available, through the current proposal, until

[44] MERC's response to DOC IR 15, attachment Rochester Design Peak Day Analysis Revised with Rochester Weather.xlsx, attached as Schedule JAU-3.

2018/2019. In fact, MERC's NNG system saw a 6.03 percent decrease in design day requirements of 15,739 Dth/day, from 261,002 Dth/day in 2014–2015 to 245,263 Dth/day in 2015/2016.[45] In response, MERC reduced its contracted firm capacity by 14,383 Dth/day in order to maintain an appropriate reserve margin. The winter period of 2015/16 had no capacity curtailments for customers served by Rochester TBS 1B or 1D.[46] The largest curtailment in the past five years occurred on January 6, 2014, the peak day for Winter 2013/2014.[47] On this day, all of MERC's Large Volume Interruptible customers were called to curtail, but Small Volume Interruptible customers were not called on to curtail usage. In fact, there have been few curtailments of interruptible customers in the Rochester area in the recent past.[48] In addition, the design day Peak Demand for each subsequent year is increased by an average annual growth rate of 1.5 percent. I believe that this forecasted growth is too high.

These problems with the forecast are not merely academic. MERC testified that it targeted its RFP to obtain natural gas supplies sufficient to match the demand it forecasts for the 2040s.[49] I will discuss in Section C why I think that is problematic from an RFP-design perspective, but it particularly problematic when the growth forecast is overly optimistic. As a result, I conclude that the problems with MERC's forecasting weighs against a finding of prudence and reasonableness.

[45] MERC's response to OAG IR 195, attached as Schedule JAU-19.
[46] MERC's response to OAG IR 117, attached as Schedule JAU-20.
[47] *Id.*
[48] MERC's response to OAG IR 117, attached as Schedule JAU-20.
[49] Clabots Direct, at 39:14–19 (noting that the Company designed its RFP to either obtain 100,000 Dth/day in new capacity, or increase existing capacity from NNG to 100,000 Dth/day).

B. MERC'S PREFERRED PROPOSAL FOR THE ROCHESTER PROJECT IS NOT A REASONABLE WAY TO MEET DEMAND FOR NATURAL GAS.

Q. Do you have concerns about the appropriateness of the Precedent Agreement that MERC negotiated?

A. Yes. Simply stated, the incremental capacity of 45,000 Dth/day for Rochester is far too high. Ratepayers will be asked to pay for a larger capital project than is justified and will be taking on the risk of a net loss on excess capacity over a long period of time. Even assuming that MERC's forecasting is accurate, the Rochester Project results in too much excess capacity, and also provides that capacity far earlier than is either necessary or useful. When incorporating the fact that MERC's forecasting is too optimistic, these problems become even greater.

Q. Discuss the amount of excess capacity over time based on the current agreement between MERC and NNG.

A. Table 6 above provides an overview of excess capacity over time for Rochester based on the Rochester Staging Plan.[50] Although capacity expansions are expected to be lumpy with excess capacity to allow for future growth, one can see by looking at Table 6, that the reserve margin for Rochester will exceed 16% to the year 2040. A reserve margin of even 16% would be higher than ratepayers should be required to pay for; the reserve margin for the earlier years is generally more than 20 percent and sometimes greater than 40 percent. Ratepayers will be receiving essentially no benefit from this excessive reserve margin, but they would still be expected to pay for it. Generally, a system-wide

[50] Mead Direct, Table 1, p. 21.

reserve margin up to five percent is considered to be reasonable.[51] In contrast, MERC is requesting reserve margins of up to ten times this "reasonable" level. And the reserve margin will be triple the "reasonable" level even 25 years from now.

MERC's proposal seeks to put current ratepayers on the hook for infrastructure upgrades and gas supply that will not be useful for decades, if they are ever necessary.[52] While I do not dispute that natural gas pipelines are "lumpy," as MERC describes, there is a difference between "lumpy" infrastructure investments and overbuilding the system. This proposal goes beyond "lumpiness" and results in overbuilding.

Q. Does MERC's ability to use firm capacity at other delivery points change the conclusion of the analysis?

A. No. The Precedent Agreement between MERC and NNG allows MERC to utilize up to 20 percent of the total Rochester firm capacity at other delivery points on MERC's system. Although this provision enhances flexibility for MERC, this additional capacity will increase the reserve margin for the rest of MERC's NNG-PGA excluding Rochester, and it is unlikely that such an increase in capacity for the entire NNG-PGA is necessary. Table 7 presents this reserve margin over time for MERC's total NNG-PGA. After Phase II of the expansion is completed, the reserve margin remains at 24 percent to the year 2040. The NNG design day provided by MERC remains constant over time.[53] Since the

[51] Department of Commerce Comments, *A Request by Minnesota Energy Resources Corporation for Approval of a Change in Demand Entitlements for its Cusomters Served off of the Northern Natural Gas Company System Effective in the Purchased Gas Adjustment on November 1, 2015*, Docket No. G-011/M-15-723, at 6 (Oct. 15, 2015).

[52] This problem could be exacerbated even further because MERC's proposal accelerates payments for the infrastructure by using a rider which is proposed to end in 2025, as well as an RFP that concentrates all of the NNG infrastructure costs into the first 25 years of a project with 50 years of useful life. MERC's response to OAG IR 140, attached as Schedule JAU-21. In addition to requiring current ratepayers to pay for infrastructure before it is useful, this approach can create some intergenerational problems.

[53] MERC's response to OAG IR 162, attached as Schedule JAU-22.

design day requirements for Rochester are increasing at an annual rate of 1.5 percent, the design day for the rest of the NNG-PGA excluding Rochester must be decreasing. Analytical justification of this assumption should be provided by the Company. This table also assumes that any of the 20 percent of additional capacity is deliverable to the rest of the MERC NNG system.

Table 6[54]
Incremental Staging Plan for NNG-PGA (Dth/Day)
45,000 Dth/day for Rochester

Winter Period	Total NNG Capacity	NNG Design Day	Reserve Margin
2015/2016	252,127	245,263	3%
2016/2017	252,127	245,263	3%
2017/2018	252,127	245,263	3%
2018/2019	268,066	245,263	9%
2019/2020	260,159	245,263	6%
2020/2021	305,159	245,263	24%
2021/2022	305,159	245,263	24%
2022/2023	305,159	245,263	24%
2023/2024	305,159	245,263	24%
2024/2025	305,159	245,263	24%
2025/2026	305,159	245,263	24%
2026/2027	305,159	245,263	24%
2027/2028	305,159	245,263	24%
2028/2029	305,159	245,263	24%
2029/2030	305,159	245,263	24%
2030/2031	305,159	245,263	24%
2031/2032	305,159	245,263	24%
2032/2033	305,159	245,263	24%
2033/2034	305,159	245,263	24%
2034/2035	305,159	245,263	24%
2035/2036	305,159	245,263	24%
2036/2037	305,159	245,263	24%
2037/2038	305,159	245,263	24%
2038/2039	305,159	245,263	24%
2039/2040	305,159	245,263	24%

[54] *Id.*, Attachment OAG-162.xlsx.

In addition, MERC's responses to discovery requests make clear that it is not a guarantee that the Company can deliver 20% of natural gas to wherever it wishes. This delivery could be limited by constraints anywhere on the system, as well as Force Majeure.[55] In other words, MERC may not be able to physically deliver gas to other points, even if it has the contractual option to do so from NNG. In particular, it may be most challenging to move gas on peak days—these are the days that it may be most beneficial to move gas to other points, but they are also the days that are most likely to have system constraints that limit that movement.

Q. Were there other projects that produces less extreme reserve margins?

A. Yes. My conclusion that MERC's request for incremental capacity of 45,000 Dth/day is too high to be reasonable is supported by the fact that a much more moderate project would have produced more reasonable reserve margins, even when accepting, *arguendo*, that MERC's forecast is reasonable.

[HIGHLY SENSITIVE TRADE SECRET BEGINS]

[55] MERC's response to DOC IR 25, attached as Schedule JAU-8.

[HIGHLY SENSITIVE TRADE SECRET ENDS] The fact that these moderate alternatives produce sufficient reserve margins so far into the future demonstrates that MERC's proposal would be overbuilding the system based on overly optimistic forecasts, too far into the future. At the very least, MERC should have provided the Commission with a full cost-benefit analysis of more moderate options.

Q. Do you have other concerns about the size of this proposal?

A. Yes. In addition to the problems with MERC's proposal for NNG-supply issues, the record also indicates some uncertainty about the appropriateness of MERC's distribution upgrade plan. MERC also needs to upgrade its distribution system to accept new supply, and it is also possible that this could result in overbuilding. In fact, MERC may have some particular incentives to overbuild its distribution system, since that is how its shareholders earn a rate of return.

MERC's testimony indicates that it is contracting with NNG for 1,001,690 therms of capacity, but has designed its distribution system in the Rochester Area (after Phase II upgrades) for 1,510,000 therms.[56] The OAG understands that some of this discrepancy is likely the result of differences between hourly flows and daily flows,[57] but MERC's

[56] MERC's response to OAG IR 147, Schedule JAU-23.
[57] MERC's response to OAG IR 189, Schedule JAU-24.

admissions indicate that some of it may be intended to support future growth that MERC hopes will materialize even *after* the 25 year forecasting horizon.

In its response to an OAG Information Request on the scale of the project, MERC stated, "We have designed the system to be able to accommodate future growth to avoid cumulative infrastructure upgrades."[58] The Petition states "MERC has designed the Rochester Project to facilitate expand [sic] capacity of its distribution system in the future should the City of Rochester continue to grow. The proposed Project has been designed for a maximum design capacity of 151,000 mcfd."[59]

While it is reasonable to expect that there will be some difference between the interstate pipeline capacity and the capacity of the distribution system, there should be more clarity and transparency before the distribution upgrades of Phase II are approved. To the extent that 50% distribution capacity above proposed supply capacity is reasonable to accommodate hourly flows, the difference may be reasonable. But MERC's statements appear to indicate that MERC is *also* building in a margin for growth even farther down the road, which MERC has not addressed or demonstrated is reasonable. As it stands, I conclude that MERC has not shown that the results of its Phase II distribution upgrades are reasonable and necessary to serve the additional load it projects.

Based on all of these concerns, I conclude that MERC's proposal for the Rochester Project, including the Precedent Agreement and its Phase II plans for proposed infrastructure upgrades, far exceeds capacity needs, possibly for many years beyond 2040.

[58] MERC's response to OAG IR 147, Schedule JAU-23.
[59] Petition, at 59.

C. MERC'S DECISION-MAKING FOR THE RFP WAS NOT PRUDENT.

Q. Do you have concerns with MERC's RFP?

A. Yes, I have five discrete concerns, which I will address individually: 1) MERC's RFP relies on forecasting that is flawed; 2) MERC's RFP is designed to obtain significant capacity before it will be useful to serve customers; 3) MERC's RFP was limited to bids that satisfied its forecasted demand out to 25 years, and did not consider more moderate or phased proposals; 4) MERC appears to have a preference for proposals that required the Company to construct a new TBS, which is a significant capital investment on which the Company will charge ratepayers a rate of return, but did not provide any analysis about the benefit of the new TBS to customers; and, 5) MERC's testimony about the options available to it are inconsistent with the information contained in the RFP responses, which the Company declined to produce until it was demanded in discovery.

1. The RFP relies on forecasting that is flawed.

Q. How is the RFP related to MERC's forecast?

A. MERC's RFP is based on its forecast. MERC drafted the RFP to seek only proposals that would satisfy the maximum demand it predicts will be required at the end of its 25 year forecast. MERC forecasts that it will require approximately 96,000 Dth/day in 2042.[60] Relying exclusively on this calculation, MERC designed its RFP to request bids that would supply 100,000 Dth/day. This means that if the forecasting is flawed, then MERC has designed its RFP to obtain more capacity than is warranted, which will place undue financial burden on its captive customers.

[60] Sexton Direct, at 40.

I have detailed my concerns with MERC's forecast above. The Company's forecast is overly optimistic about growth in the region, and it is based upon insufficient historical data and speculative growth based on the Mayo Clinic Expansion and the DMC Initiative.[61] MERC's RFP assumes that MERC will require 100,000 Dth/day in the 2040s, which is based exclusively on a flawed forecast.

Q. Do you believe that it was reasonable for MERC to limit its RFP to only consider proposals that add 45,000 Dth/day?

A. No. First, regardless of MERC's forecast, it was simply unreasonable for the Company to limit its RFP in this way. Instead, the Company should have seriously considered all alternatives, and in particular alternatives that would have provided shorter term capacity solutions without the risk created by obtaining so much excess capacity over such a long term. Second, by tying the RFP so closely to its forecast, MERC has placed significant weight on the forecast. As I have described above, I identified problems with MERC's forecast. If the forecast is not accurate, then the RFP and the responses MERC received will be providing more capacity than is necessary. There is some risk involved in assuming that the DMC program will lead to significant growth in the Rochester area. While it is possible that the DMC will spur significant growth in Rochester, it is problematic that this uncertainty plays a major role in the MERC forecast. By tying its RFP to its assumptions about DMC related growth, MERC is proposing that ratepayers be required to pay for capacity additions that may not be necessary. Even assuming what I consider an unlikely high growth in demand, the persistent high reserve margin out to

[61] Petition, at 77-78.

2040 indicates that customers will be paying for an excess reserve margin far into the future.

2. MERC's RFP will require ratepayers to pay for excess capacity long before it will be necessary or useful.

Q. Can you discuss the timing problems related to the proposal?

A. Even assuming that MERC's forecasting was sound, MERC's RFP is designed to obtain 100,000 Dth/day in the short-term, when that capacity will not be necessary for decades. Current firm ratepayers will pay for that infrastructure for years before it becomes useful, which is an unreasonable burden to place on captive customers. It is also important to note that the excess capacity will be a significant benefit to customers who can obtain transport service, or who seek to move to interruptible rates with no concern of ever being curtailed.

3. Limiting the scope of the RFP means that MERC did not seriously consider more moderate or phased in proposals.

Q. Can you discuss MERC's limitation of the scope of the RFP?

A. Yes. By limiting the RFP to bids that would supply 100,000 Dth/day immediately (which is nearly double its current requirement), MERC prejudged the value of more moderate approaches. Making massive capital investments up-front, on the assumption that future growth will materialize, places significant risk on ratepayers. MERC's ratepayers are captive customers—by filing rate cases the Company can ensure it remains financially whole regardless of whether growth materializes, but ratepayers have no protection if growth slows. MERC's RFP categorically does not solicit more moderate proposals, or phased proposals that could have minimized risks to ratepayers while still providing short-, medium-, and long-term solutions.

MERC obtained the services of a consultant to conduct an independent analysis of some of the bids. MERC exacerbated this problem when it chose to limit the scope of the review of Mr. Sexton. I believe that MERC has also conducted an internal analysis, but MERC has not provided that information in the record to my knowledge.

Q. Can you describe Mr. Sexton's analysis?

A. Yes. Mr. Sexton performed a Net Present Value ("NPV") analysis of NNG Proposal 3.0, the ultimate agreement with NNG, the proposal by Twin Eagles, and the proposal from Northern Borders.[62] Based on this analysis, Mr. Sexton concluded that the NNG Proposal 3.0 was "the lowest cost alternative to MERC" to obtain the 100,000 Dth/day it requested in its RFP.[63] Mr. Sexton also concluded that the subsequent modifications MERC negotiated to NNG Proposal 3.0 provided additional value above and beyond NNG's initial proposal.[64]

Q. Do you have any concerns with Mr. Sexton's analysis?

A. I do. Regardless of Mr. Sexton's NPV methodology, I believe that it is more concerning that MERC did not direct Mr. Sexton to include an evaluation of all of the RFP responses. Mr. Sexton indicates that he compared the responses from Northern Border, Twin Eagle, and NNG Proposal 3.0. **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS]. With this limitation, Mr. Sexton concluded that NNG's proposal provided better value than the proposals from Twin Eagle and Northern Border.

[62] Sexton Direct, at 43–45.
[63] *Id.*
[64] *Id.*

Q. What was the impact of the limited scope of the RFP and the limitations on Mr. Sexton's review?

A. In particular, it appears that NNG **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS] From this record, it appears that MERC essentially disregarded these proposals because they did not satisfy MERC's requirement to obtain 100,000 Dth/day of capacity (which, as noted above, is based on a flawed forecast).

For example, **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS], which would provide significant reserve margins above and beyond the forecasted use past 2026/2027, when the Company's flawed forecast anticipates a design day of 70,641 Dth/day. This proposal would have cost only **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS]. This phased approach does not cost significantly more than MERC's proposal for the Rochester Project, but would protect ratepayers and, as NNG described it, **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS].

4. MERC did not consider the extra cost to ratepayers of choosing a proposal that required the Company to construct a new TBS in analyzing the responses to the RFP.

Q. Can you discuss the matter of the new TBS?

A. MERC has selected a proposal that requires the Company to construct a new TBS, which will cost millions of dollars. Many of the proposals in response to the RFP would not have required a new TBS.[65] It would obviously be financially beneficial for MERC to construct a new TBS, on which it would earn its rate of return, as opposed to relying on assets which have depreciated; as such, this analysis is essential to the decision about which proposal is best for ratepayers. It is possible that the upgrades necessary to existing TBSs would have been more burdensome fore ratepayers than a new TBS, but it does not appear as if MERC has conducted that analysis on this record.

5. MERC did not accurately describe the responses to the RFP in its Petition or Testimony.

Q. Can you discuss your concerns with MERC's descriptions of the responses to the RFP?

A. I am concerned with the manner in which MERC has described NNG's response to the RFP. Specifically, Ms. Mead testifies that "NNG advised us that the only available alternative was to make a major expansion of the pipeline system into the Rochester area. This proposal, while larger than we needed in the near term, compared favorably against other proposals that would have required an equivalent major expansion by building a new pipeline into the area."[66] This appears to be directly contradictory to NNG's

[65] Mead Direct, at 11.
[66] Mead Direct, at 27.

response to the RFP. As I have noted previously, in that RFP **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS]

MERC's discussion of NNG's proposals does not appear to match up with NNG's actual proposals, which I find doubly concerning since MERC did not provide any substantive discussion of the alternatives, and in fact did not produce either the RFP or the responses to the RFP until prompted through discovery.

6. Conclusion regarding MERC's handling of the RFP.

Q. What is your opinion of MERC's handling of the RFP?

A. Based on these concerns, I do not believe that MERC has demonstrated that it acted prudently in regard to either the design of the RFP or its consideration of the responses. The larger point I wish to make is that MERC's RFP should have been structured in such a way that the Company received bids for a more moderate project that would result in a more reasonable level of reserve margin. In particular, it appears that MERC rejected several alternate proposals suggested by NNG that would have been more moderate and would not have carried such significant risk for ratepayers.

D. MERC DID NOT CONSIDER ALL ALTERNATIVES TO THE ROCHESTER PROJECT.

Q. Did MERC consider all possible alternatives or modifications to the Rochester Project?

A. It does not appear so. In particular, MERC did not consider peak-shaving alternatives. It also appears that MERC did not press NNG on the possibility of saving costs by installing a smaller compressor than the one that NNG has selected.

1. Peak Shaving Alternative.

Q. Did MERC consider non-pipeline alternatives?

A. Yes. In its Initial Petition, the Company described the "limited alternatives" it considered, which, in addition to a transmission pipeline alternative, included distribution system upgrades, energy conservation, and taking no action.[67]

Q. Please describe the Company's analysis of these options.

A. The distribution system upgrade option consisted of "different design options" to achieve the goal of reinforcing and interconnecting certain distribution facilities and standardizing system operating pressures in order to effectively manage the increased capacity from the interstate pipeline expansion. This appears to not be an alternative to the project so much as a secondary phase necessitated by the interstate pipeline upgrades. The energy conservation alternative was deemed to be "not a viable alternative" to addressing growth in the Rochester area. Finally, the no-build alternative failed because "[t]here is simply no additional transmission capacity available to alleviate the shortage of capacity in the Rochester area."[68]

[67] Petition, at 26.
[68] Petition, at 28.

Q. Are you aware of other non-pipeline alternatives that MERC could have considered to meet its design day firm demand?

A. Yes. Other Minnesota natural gas utilities (CenterPoint Energy and Xcel Energy) utilize peak-shaving facilities to meet design day firm demand.[69]

Q. What is a peak-shaving facility?

A. A peak-shaving facility can be used by a gas distribution utility to meet design day firm demand on its distribution system during the coldest days of the season. These facilities can encompass technologies such as propane-air or liquefied natural gas ("LNG"), which are technologically distinct but serve the same functions—to meet the "needle peaks" of gas demand that occur during the coldest days of the season while also reducing annual upstream pipeline reservation charges that would have been necessary had the distribution utility depended upon interstate pipelines only to meet design day demand.[70] Across the state, over 20 percent of utilities' demand day requirements are met by peak-shaving facilities.[71]

[69] *See* Review of 2013–2014 Annual Automatic Adjustment Reports, *Natural Gas Utilities' 2013–2014 Purchased Gas Adjustment (PGA) True-Up Filings*, Docket No. G-999/AA-14-580 80 (May 5, 2015).
[70] *U.S. LNG Markets and Uses*, U.S. Energy Information Admin. 8–11 (2003).
[71] Review of 2013–2014 Annual Automatic Adjustment Reports *Natural Gas Utilities' 2013–2014 Purchased Gas Adjustment (PGA) True-Up Filings*, Docket No. G-999/AA-14-580 71, Table G16 (May 5, 2015).

Q. Did MERC consider peak-shaving as an alternative?

A. No, it did not. When asked about existing or planned peak-shaving facilities on its system, MERC stated that it "no longer has any peaking facilities on its system."[72] In addition, MERC stated that additional peaking facilities "would not be an effective solution to serve existing and forecast firm demand" because peaking facilities "do not increase firm capacity on a system that has already reached its maximum capacity."[73] MERC concluded by saying that peak-shaving facilities "will not increase capacity of the already-constrained system."[74]

Q. Do you agree with MERC's response?

A. I would like to clarify that there is a subtle yet important distinction between two types of capacity at issue in this case. First, there is the capacity of the town border station ("TBS") or city gate to receive gas from the interstate pipeline, which in some ways is a supply problem. Second, there is the capacity of the distribution system to take the gas from the town border station and distribute it to end-use customers at adequate pressures. Given the description of work that MERC plans to do in this case, it appears that the Company has capacity constraints of both types in the Rochester area. The solutions to these problems are related, yet distinct; selecting an alternative to fix the TBS capacity problem will likely influence the design of the distribution-side work that is necessary to deliver the newly-added gas.

One primary function of peak-shaving facilities is to ensure delivery of gas to firm customers on the very coldest days of the season. This function addresses the issue

[72] MERC's response to OAG IR No. 176, attached as JAU Schedule-25.
[73] *Id.*
[74] *Id.*

of TBS capacity, or overall supply of natural gas, because the peak-shaving facility can displace some amount of gas that would otherwise be delivered by the interstate pipeline. It also appears that peak-shaving facilities can help alleviate distribution capacity concerns in some instances, depending on the design of the facility and the configuration of the distribution system.[75] Therefore, MERC's response that adding a peak-shaving facility will not fix its distribution capacity problems may be reasonable. But, there is no indication that the Company actually undertook the analysis necessary to determine whether a peak-shaving facility could meet its needs in Rochester.

Q. Do you recommend a peak-shaving alternative?

A. Not necessarily. I do not have the information or expertise to allow for the analysis that would lead to such a recommendation. My main criticism is MERC's approach to its analysis of alternatives—had MERC thoroughly investigated alternatives such as peak-shaving and still concluded that the interstate pipeline alternative was the most reasonable, prudent alternative, then there would at least be some clarity as to the Company's decision making process. But MERC has given no indication in the record thus far that it ever seriously considered non-pipeline alternatives to meet its short- and long-term needs.

[75] A Maryland Public Service Commission report on Baltimore Gas and Electric's ("BGE") propane and LNG facilities indicated that the peak-shaving facilities there served a distribution-side function due to their design and location that allowed the utility to avoid installation of additional distribution piping.

> "Without these [peak-shaving] facilities, even if all of the physical gas supply to meet consumption could be obtained from the interstate pipeline at BGE's city gates, current distribution system piping is insufficient to deliver the gas to all customers while still maintaining adequate system pressure. To serve customers exclusively with interstate pipeline gas under design day-like conditions, BGE would have to reinforce its distribution piping in order to maintain the pressures needed to provide customers with reliable gas service."

Staff Report on the Baltimore Gas and Electric Company's LNG and Propane Facilities, *In the Matter of the Application of the Baltimore Gas and Electric Company for Revision in its Gas Rates*, Case No. 8829, at 4 (Oct. 2, 2000), attached as exhibit JAU-26.

2. Smaller Compressor Alternative.

Q. Are there modifications to the current expansion plan that should be considered.

A. Yes. The OAG inquired into the size of the compressor recommended for the current expansion plan.[76] The current proposal includes a 15,000-hp compressor at a cost of $27 million.[77] In response to IR 161, MERC stated that "The flow rate requires a compressor site rating of at least 13,500 horsepower" but the next smallest unit available from its vendor was only 10,000-hp. **[HIGHLY SENSITIVE TRADE SECRET BEGINS]**

[HIGHLY SENSITIVE TRADE SECRET ENDS]

E. CONCLUSIONS REGARDING THE PRUDENCE AND REASONABLENESS OF MERC'S PROPOSAL FOR THE ROCHESTER PROJECT.

Q. What is your conclusion regarding the prudence and reasonableness of MERC's proposal?

A. I conclude that MERC has not demonstrated that the Commission should grant and advanced determination of prudence for its proposal. I base this conclusion on all of the analysis above, but summarize the concerns briefly here.

First, MERC's forecasting is overly optimistic and not reasonable. Second, even assuming that MERC's forecasting was on point, MERC's proposal for the Rochester project provides far too much capacity, and provides it far earlier than it will be used or useful. Third, because MERC's RFP was targeted to provide the full amount of capacity

[76] MERC's response to OAG IR 161, attached as Schedule JAU-27.
[77] MERC's response to OAG IR 148, attached as Schedule JAU-28.

that MERC forecasted for the 2040s, MERC's RFP was designed to obtain too much capacity and MERC did not consider more moderate proposals that would have solved supply problems without exposing ratepayers to excessive risk based on long-term growth projections that may never materialize. Fourth, it appears that MERC did not consider non-pipeline alternatives, such as peak shaving facilities, and did not press NNG on the size of its compressor, which represents a significant cost to the project.

Based on these problems, I conclude that MERC has not demonstrated that its project is a reasonable way to meet demand for natural gas in the Rochester area.

Q. What is your recommendation?

A. Primarily, I recommend that the Commission find that MERC's proposal for the Rochester project is not prudent and reasonable, and order MERC to find an alternate solution that does not obligate ratepayers to pay for excessive reserve margins decades before that capacity may be useful. In particular, I believe that some of the phased proposals offered by NNG should have been considered more seriously.

Q. Do you have an alternate recommendation?

A. Yes. While my primary recommendation is that the Commission find that MERC's proposal for the Rochester project is not prudent and reasonable, I have one alternative to suggest. If the Commission wishes to proceed with the Rochester Project at this time regardless of the concerns I have identified, some of the financial problems of MERC's proposal could be mitigated by providing ratepayer protections from excess capacity. In particular, *only* if the Commission orders MERC to move forward now, I would recommend that the Commission make a finding that only part of the Rochester Project is used and useful—the part that is necessary to serve existing demand plus a reasonable

reserve margin in 2025 such as the 5% suggested by the DOC in other proceedings. The purpose of such a finding would be to allow MERC to move forward with its preferred project, but protect ratepayers from overbuilding capacity until such time as that capacity becomes necessary, or used and useful.

I am not an accountant and cannot provide a precise recommendation on how to resolve the accounting for such a finding. I request that the Company provide a discussion of the possible solutions in its Rebuttal Testimony.

IV. REVIEW OF MERC'S PROPOSED COST ALLOCATIONS FOR THE ROCHESTER PROJECT.

Q. What costs will be incurred to provide additional capacity to accommodate the current and future capacity needs in the Rochester area?

A. The Rochester Projects addresses two areas of need. First, the distribution system will need to be upgraded in order to distribute the additional capacity efficiently and reliably. The cost of upgrading the distribution system, called Phase II, is currently estimated to be about $44 million, and will be recovered through a combination of an NGEP Rider and base rates through rate case filings. Second, NNG infrastructure needs to be upgraded to supply MERC with additional capacity. The NNG portion of the project costs is approximately $60 million, and will be recovered through the PGA for NNG customers.[78]

[78] Lee Direct, at 4.

Q. How will the costs of the Phase II upgrades be allocated?

A. MERC is seeking approval to recover the Phase II costs from all MERC ratepayers.[79] MERC states that this cost allocation across all MERC customers is consistent with Minnesota statutes and past Commission practice.[80] In addition, MERC states that if the Commission were to allocate the costs only to Rochester area customers, "those customers' cost burden would outweigh the benefit they receive," although the OAG takes no position on whether MERC's statement is reasonable.[81] Table 9 below provides the comparison of the cost impact on the average residential customer under three cost allocation mechanisms.

Table 9[82]

Distribution Rate Impact of Phase II Costs Annual Average Residential Customer Impact			
Calendar Year Impact	Rochester Only (867 therms)	NNG PGA (867 therms)	All MERC Customers (867 therms)
2016	$0.68	$0.09	$0.09
2017	1.65	0.23	0.23
2018	21.93	4.32	1.51
2019	96.59	22.05	2.72
2020	151.64	35.44	3.29
2021	153.77	35.94	3.97
2022	155	36.19	4.53
2023	153.32	36.01	4.67
2024	146.25	34.87	3.97
2025	139.39	34	3.30

[79] *Id.* at 4.
[80] *Id.* at 22.
[81] *Id.* at 34.
[82] *Id.* at Exhibit (ASL-1), 1–2.

Narrowing the cost allocation to the Rochester and the NNG PGA ratepayers has a substantial impact on the average residential customer. While the situation is relatively unusual given that there is such a large infrastructure investment for the benefit of one area, MERC has an obligation to meet the demands of all of its existing customers and the costs of meeting that demand are generally spread over all customers. While the issue is somewhat murky because MERC requests recovery under a new statute that appears to be targeted to line extensions, where costs are not spread through the whole customer base, this scenario is a distribution upgrade, albeit a large one that involves interstate pipeline upgrades, which are generally not socialized at the FERC level. In addition, I recognize that limiting the costs to Rochester customers would create a significant financial burden on those customers.

The OAG is open to a discussion of alternative solutions, but at this time does not dispute MERC's recommendation to recover Phase II costs from all ratepayers. The OAG does, however, have concerns about how the costs are allocated to different customer classes.

Q. How will the Phase II costs be allocated across MERC's customer classes?

A. MERC proposes to allocate Phase II costs across all customer classes via distribution rates.[83]

Q. How will the cost of upgrades to the NNG system be allocated?

A. The upgrade costs to the NNG system will be recovered through MERC's NNG Purchased Gas Adjustment ("PGA") and not allocated across all MERC ratepayers.[84] In addition, under the current proposal, the costs associated with the NNG upgrades will be

[83] *Id.* at 4.
[84] *Id.* at 5.

allocated to firm customers only. Firm customers include the Residential, Small Commercial and Industrial (SC&I) and Large Commercial and Industrial (LC&I) customers. Under the current proposal Transport and Interruptible customers are not currently allocated any of the NNG upgrade costs.[85]

Q. Is it possible to allocate the increased capacity costs to the other customer classes?

A. Yes. In responses to OAG IR requests, MERC has provided the impacts of various cost allocation scenarios. These estimates are presented in Table 10 below.

Table 10
Annual Average Residential Customer Impact

(867 therms)

Calendar Year Impact	Rochester Firm Customers[1]	NNG-PGA Firm Customers[1]	NNG-PGA Firm and Interruptible Customers[2]	NNG-PGA Firm, Interruptible and Transport Customers[3]
2018	11.37	2.81	2.48	1.07
2019	77.91	19.33	17.07	7.42
2020	129.27	32.16	28.42	12.43
2021	127.14	31.98	28.25	12.41
2022	124.97	31.66	27.98	12.35
2023	122.78	31.34	27.71	12.3
2024	120.56	30.9	27.34	12.22
2025	118.35	30.7	27.17	12.19
[1]Lee Direct Testimony, Exhibit_(AS-1), p. 3.				
[2]MERC Response to OAG IR-171, Attachment_OAG_171Part3.xlsx attached as Schedule JAU-30				
[3]MERC Response to OAG IR-173, Attachment OAG_173.xlsx. attached as Schedule JAU-31				

Q. Is the cost allocation for NNG capacity appropriate with cost commensurate with benefit?

[85] MERC's response to DOC IR 33, attached as JAU Schedule-29.

A. Yes and no. It is appropriate for the cost of NNG upgrades to be spread across the NNG-PGA rather than just Rochester. As Ms. Lee points out in her Direct Testimony, the supply of firm capacity will not just increase in the Rochester area but for MERC customers throughout southeastern Minnesota. Under the current proposal capacity can be made available at any delivery point in MERC's NNG PGA without any cost penalty. Additional capacity available for delivery points across the NNG PGA also provides MERC with "significant operational flexibility." In addition, allocating costs solely to Rochester customers would be significant and burdensome.[86]

However, restricting cost allocation to firm customers for the NNG upgrades is not commensurate with benefit. Under the current expansion proposal, MERC's reserve margin will significantly increase for many years into the future. This will significantly benefit interruptible customers by making the probability of curtailment extremely unlikely for many years into the future. According to MERC's forecast, which I believe overstates growth, MERC will have a reserve margin greater than 20 percent for approximately 20 years. Curtailments in the Rochester area have already been rare.[87]

Transportation customers will also benefit from expanded capacity. It will make it possible for transportation customers to use the excess capacity available after firm system sales have been met. The increased capacity will enable more competitive rates and other favorable contract terms for transportation customers. Even transportation

[86] Lee Supplemental Direct, *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-011/GR-15-736, at 27 (Dec. 30, 2015).
[87] MERC's response to OAG IR 117, attached as Schedule JAU-20.

customers that do not directly use the additional laterals will benefit from the expansion due to displacement which will make it easier to move gas.[88]

It is possible to allocate a portion of the cost to interruptible customers through the commodity portion of the PGA. The Commission approved a similar approach in MERC's Bison/Norther Border Pipeline Contract.[89] There is not much of an impact differential by including the NNG-PGA interruptible customers. However, the impact is quite substantial if cost is allocated across transport customers as well. Allocating across the transport customers cuts the impact on the average residential customer by more half.

Q. Do you have any additional concerns about customer class allocations?

A. Yes. I also have concerns about MERC's interruptible discounts. Interruptible customers receive a significant rate discount in return for their agreement to curtail capacity when it is needed. MERC's proposal, however, would mean that interruptible customers would have essentially no risk of curtailment. Large customers, or any customer who has the option, will be incentivized to change to interruptible service, even though that service will be essentially the same as firm service because the risk of curtailment is so low. In a normal situation, firm customers receive the benefit of not being required to pay for infrastructure sufficient to ensure continuous service to interruptible customers. In this case, though, firm customers are being asked to pay for so much excess capacity that interruptible customers are not really providing any benefit to the system.

[88] Lee Supplemental Direct, *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-011/GR-15-736, at 28–29 (Dec. 30, 2015).

[89] Docket Nos. G-011/M-11-1082, G-011/M11-1083, G-011/M-11-1084, G-007/M-11-1088; *see* MERC response to OAG IR 171, attached as JAU Schedule-30.

As a result, it may no longer be reasonable for interruptible customers to receive the same discount. I ask MERC to respond to this concern in its rebuttal testimony in detail by discussing interruptible discounts in the context of its proposal, and whether changes to those discounts may be necessary.

Q. What is your recommendation for allocation?

A. I recommend that the costs be allocated to all customer classes, including interruptible and transport customers, and not restricted to just firm customers. In addition, I ask MERC to provide testimony justifying its interruptible discounts given the excessive reserve margins the Company seeks to create.

V. INFORMATION ABOUT OTHER MATTERS.

Q. Why is it necessary to address other matters?

A. In this Section, I will briefly address three additional matters. Specifically, when it referred this proceeding to the Office of Administrative Hearings, the Commission sought analysis on whether the Rochester Project comports with the City of Rochester's stated goal of using 100% renewable energy. The Commission also sought analysis on whether there are any other sources of funds available for the Rochester Project. In addition, I will also briefly discuss the matter of whether the Rochester Project is eligible for recovery under the NGEP Rider statute.

A. THE CITY OF ROCHESTER'S 100% RENEWABLE ENERGY GOAL.

Q. Do you believe that the Rochester Project is consistent with the City of Rochester's goal to use 100% renewable energy?

A. The Commission requested that parties address whether the Rochester Project is consistent with the City of Rochester's stated goal of using 100% renewable energy by 2031.[90] It seems obvious that increasing the consumption of natural gas in the Rochester area would increase the use of a fuel source that is not renewable. While discussions about "renewable energy" generally focus on electric utilities, rather than natural gas utilities, the transport of natural gas by MERC has environmental and social impacts that are somewhat comparable to the concerns related to electricity production. In addition, I am aware that Rochester Public Utilities ("RPU"), the municipal electric utility, intends to construct a natural gas fired peaking plant in the Rochester area, and that RPU intends to use **[TRADE SECRET BEGINS] [TRADE SECRET DATA ENDS]** of natural gas from MERC to operate the plant.[91] In this way, it appears that the combination of the Rochester Project and RPU's plans is not consistent with the City's goal of using 100% renewable energy.[92]

To clarify the matter, the OAG contacted the City of Rochester to discuss its goal of using 100% renewable energy. City officials informed the OAG that, while the Mayor of Rochester has issued a proclamation that the City will use 100% renewable energy by 2031, the proclamation does not have the force of law. In particular, the City Council has not taken up the 100% renewable energy proclamation, and no work has been done to

[90] Paul Huttner, *Rochester eyes 100 percent renewable energy by 2031*, Minnesota Public Radio News, Oct. 13, 2015, http://blogs.mprnews.org/updraft/2015/10/city-of-rochester-100-renewable-energy-goal-by-2031/.

[91] Niala Charles, *New Rochester energy project approved*, Fox 28, Feb. 24, 2016, http://www.fox28.com/story/31304704/2016/02/24/new-rochester-energy-project-approved; *see also* MERC's response to OAG IR 156, attached as Schedule JAU-32.

[92] It is worth noting that MERC claims to have been unaware of RPU's plan until it was reported on in local papers. *See id.* I believe that this raises some concerns about the thoroughness of MERC's investigation into the future demand for natural gas in the area.

analyze the cost or feasibility of accomplishing the goal.[93] As a result, while it appears that the Rochester Project may be inconsistent with a 100% renewable energy goal, I did not include that consideration in my analysis given this information.

B. AVAILABILITY OF OTHER SOURCES OF FUNDS FOR THE ROCHESTER PROJECT.

Q. Why did the Commission request analysis of whether any other sources of funds are available for the Rochester Project?

A. The NGEP Rider statute contains a provision that requires MERC to identify the amounts of contributions in aid of construction ("CIAC"), as well as to describe its efforts to obtain CIAC, in its request for rider recovery. If an NEGP Rider is ultimately approved, these CIAC are applied to reduce the revenues collected from ratepayers. CIAC also generally arise when utilities pursue service extension projects.

As MERC described in its testimony, "if a new line extension is not a net revenue generator over the course of the line's life, the policy requires MERC to recover the deficiency from the new customer through a [CIAC]."[94] After reviewing the record, it appears that this project is not intended to be a net revenue generator, in that MERC has confirmed that it has not attempted to forecast the sales it will generate over the life of the project.[95] If this were a normal extension project, MERC would normally be required to obtain CIAC to pursue the project. In this context, however, MERC states that the

[93] Correspondence from Mark Kotschevar, General Manager of Rochester Public Utilities, June 3, 2016, attached as Schedule JAU-33.
[94] Lee Direct, at 21.
[95] For example, MERC states that the Rochester Project will generate $14.0 million through 2025, but requests to recover far more than that from ratepayers over that time period. MERC's response to OAG IR 139, attached as Schedule JAU-34.

Rochester Project does not have "a particular customer or customer group in mind," and so there is no identifiable new customer that could contribute.[96]

I believe that the Commission may have been specifically referring to the availability of state infrastructure aid funding from the Destination Medical Center Corporation ("DMCC").

Q. What is the DMCC?

A. The DMCC is a non-profit corporation responsible for providing public oversight of the Destination Medical Center development in the Rochester area. Under Minnesota Statutes section 496.47, it is possible that state funding may be available for infrastructure projects to support the Destination Medical Center development. According to MERC, there are several impediments to obtaining funding for the Rochester Project. While MERC discussed these concerns in its testimony, it provided a more comprehensive response in response to OAG Information Requests 126 & 127, which I have attached as Schedule JAU-35.

First, no state infrastructure aid is available until a threshold of $200 million in private investment has been made.[97] MERC states that this threshold has not been satisfied, and, as a result, there is no state infrastructure funding available. Second, MERC states that it may not be eligible for infrastructure funding because the infrastructure in question will be owned by MERC, an investor-owned utility, rather than publicly owned. Third, MERC states that the Rochester Project is not physically located in the Medical Center Development District.

[96] Lee Direct, at 34.
[97] Minn. Stat. § 469.47, subd. 3(a).

Despite these challenges, MERC indicates in its testimony that it did file an application for $5 million in state infrastructure funding from the DMC, although that application was not filed until April 15, 2016, approximately seven months after MERC's initial petition in this proceeding.[98]

Q. Do you have an opinion as to whether DMC funding should be available to MERC for the Rochester Project?

A. No, but I would like to introduce some information into the record to ensure that the Commission has as much information about the issue as possible.

First, in regard to the $200 million private investment requirement, it seems likely that this threshold will be met at some time during the useful life of the Rochester Project. When that occurs, state infrastructure aid may become available. As a result, this appears to be a problem related to timing.

Second, as to the other problems, it is unclear whether or not these are fatal impediments. MERC states that these problems can be resolved by amendment of the DMC Plan.[99] The DMC Plan can be obtained from the DMC's website at http://dmc.mn/plan-priorities/. I do not attach it in full to my Testimony, as it is voluminous, but I believe it should be available to the Commission and so incorporate it by citation.

Q. Can you provide any additional information for the record?

A. Yes. To some extent the Commission is required to rely upon MERC for an account of its efforts to secure funding from the DMC. It is not clear that MERC has a financial

[98] Lee Direct, Schedule ASL-3.
[99] MERC's response to OAG IRs 126 & 127, attached as Schedule JAU-35.

interest in obtaining alternate funding, because that could impact the amount of investments on which the Company earns a rate of return in the future.

To obtain more information, the OAG requested that MERC provide its communications sent to or received from the DMC through discovery. MERC declined to actually produce all of its communications, but did narratively describe some communications it has had with the DMC. I attach this discovery response for the Commission's information.[100] The communications that were produced appear to indicate that MERC did not discuss the Rochester Project with the DMC until February 15, 2016, nearly four months after it filed its Initial Petition in this proceeding. While it appears that MERC had a meeting about its request on May 18, 2016, MERC has not updated the OAG on the results of its application or the DMC's response to its application for funding.

I also attach an information request from MERC addressing why it limited its application of funding from the DMC to only $5 million, while the Rochester Project will ultimately cost more than $100 million.[101]

Q. Do you have a recommendation regarding the availability of funding from the DMC?

A. Not at this time. The availability of funding from the DMC is a legal matter that the OAG will address in its briefs, to the extent that it is raised. In addition, it appears that MERC has an outstanding application for funding from the DMC. The OAG expects that MERC will provide an update on the status of that application when the information is available.

[100] MERC's response to OAG IR 199, attached as Schedule JAU-18.
[101] MERC's response to OAG IR 170, attached as Schedule JAU-36.

C. ELIGIBILITY FOR RECOVERY UNDER THE NGEP RIDER.

Q. Do you provide testimony on whether the Rochester Project is eligible for recovery through the NGEP rider?

A. No. I am not an attorney, and do not testify as to the interpretation of statutes. Instead, I focus on determining whether the Rochester Project is a reasonable manner of satisfying future demand for natural gas in the Rochester region.

Q. Does the OAG have concerns about the eligibility of the Rochester Project for the NGEP Rider?

A. It is my understanding that attorneys at the OAG are reviewing whether the Rochester Project is eligible for NGEP Rider recovery. Because of the nature of this proceeding, however, that legal analysis must be reserved for the OAG's Initial Brief following the evidentiary hearing.

I raise the issue now because the OAG wants to ensure that MERC is aware that the issue of rider eligibility may be raised in the future.

VII. CONCLUSION.

Q. Is the Company's forecast reasonable?

A. The demand forecast conducted by the Company is too high and has insufficient historical basis. It is based on only eight years of data. The forecast also incorporates expectations of future growth which are based on the Mayo Clinic Expansion and the DMC Development Plan which introduces uncertainty into the forecast.

Q. Has the Company demonstrated that there is a current need to increase natural gas capacity for customers in the Rochester area?

A. Based on the current design day, there is an immediate need for additional capacity in the Rochester area.

Q. Has the Company proposed a reasonable project to satisfy that need?

A. The proposed increase in capacity is too high. Even assuming what I consider an unlikely high growth rate, the reserve margin will be nearly 17 percent for Rochester and 24 percent for the NNG-PGA out to the year 2040. As pointed out in the balance of my testimony, this large of a reserve margin, this far into the future, is not reasonable and requires ratepayers to pay for an excess reserve margin far into the future.

Q. Did MERC act prudently in designing and considering responses to its RFP, as well as other alternatives?

A. No. I have outlined above my concerns for the design of MERC's RFP and its handling of the responses. In particular, MERC designed its RFP to obtain only responses that would satisfy its full, unreasonable, growth projections out past 2040, and did not consider more moderate proposals that would address current needs without exposing ratepayers to significant risk of overbuilding based on long-term growth projections that may never arise. MERC also did not analyze non-pipeline solutions such as peak shaving facilities, which most other natural gas utilities in Minnesota use to manage their supply peaks. A peak shaving facility and the distribution upgrades of Phase I, which are already completed, may have been able to address current and more near-term future needs.

Q. What is your recommendation regarding the reasonableness and prudence of MERC's proposal?

A. I conclude that MERC's proposal is not reasonable or prudent, and recommend that the Commission make such a finding. To the extent that MERC needs to deal with demand for natural gas in the Rochester area, the Company should make a different plan that proposes more moderate solutions without exposing ratepayers to extensive risk.

In the alternative, I recommend that the Commission find that a portion of the Rochester Project that results in excess reserve margins is not used and useful. I recommend that the Commission not allow recovery of this portion of the Project until the Company later demonstrates that growth has made it necessary to provide this amount of capacity to firm customers. I believe that a starting point for determining the portion to be found as not used and useful is a reserve margin in 2025 no greater than 5 percent as discussed by the Department in recent demand entitlement filings.

Q. If the project is built, what is your recommendation for allocating costs of the project?

A. At this time, I do not dispute the Company's allocation of the cost of upgrading the distribution system across all MERC customers. However, the Company is currently allocating the cost of upgrading the NNG system to only firm customers. As discussed in my testimony, both transport and interruptible customers will benefit from such a large capacity expansion on the NNG pipeline. The transport customers will benefit from more competitive rates and favorable contract terms and the interruptible customers will be able to benefit from discounted interruptible service for many years into the future with no risk of curtailment. I recommend that these costs be allocated across all customer

classes, including transport and interruptible customers, so that costs are commensurate with benefits.

I also recommend that MERC provide testimony justifying its interruptible discounts in an environment with such excess reserve margins.

Q. Does this conclude your testimony?

A. Yes it does.

List of Schedules

#	Description
1	*Curriculum Vitae* of Dr. Julie Urban
2	MERC's Response to OAG IR 134
3	MERC's IR Response to DOC IR 15 (with attachment)
4	MERC's Request for Proposal
5	Responses to MERC's RFP (Highly Sensitive Trade Secret, available only in 16-315)
6	Summary of RFP Responses (Highly Sensitive Trade Secret, available only in 16-315)
7	Precedent Agreement between MERC and NNG (Trade Secret)
8	MERC's Response to DOC IR 25
9	MERC's Response to OAG IR 155
10	MERC's Response to OAG IR 155.6
11	MERC's Response to DOC IR 13
12	MERC's Response to OAG IR 107 (Trade Secret data excised)
13	MERC's Response to OAG IR 123
14	MERC's Response to OAG IR 155.7-2
15	MERC's Response to OAG IR 155.7 (Residential UPC Supplemental Response)
16	MERC's Responses to DOC IRs 6–8
17	MERC's Response to OAG IR 125
18	MERC's Response to OAG IR 199 (with attachment)
19	MERC's Response to OAG IR 195
20	MERC's Response to OAG IR 117
21	MERC's Response to OAG IR 140
22	MERC's Response to OAG IR 162 (with attachment)
23	MERC's Response to OAG IR 147
24	MERC's Response to OAG IR 189
25	MERC's Response to OAG IR 176
26	Maryland Public Service Commission's Report on BG&E's Peak-Shaving Facilities
27	MERC's Response to OAG IR 161
28	MERC's Response to OAG IR 148
29	MERC's Response to DOC IR 33
30	MERC's Response to OAG IR 171 (with attachment)
31	MERC's Response to OAG IR 173 (with attachment)
32	MERC's Response to OAG IR 156 (Trade Secret data excised)
33	Correspondence from Rochester Public Utilities
34	MERC's Response to OAG IR 139
35	MERC's Response to OAG IR 126 & 127
36	MERC's Response to OAG IR 170

PROFESSIONAL BACKGROUND AND EDUCATION

Education

Valparaiso University……..B.A. in Economics
University of New Mexico……..M.A. in Economics
University of New Mexico…….Ph.D. in Economics

Professional Seminars

"Demand Forecasting School" three-day program
Institute of Public Utilities at Michigan State University……...2012

"Regulatory Studies "Camp NARUC" two-week program"
Institute of Public Utilities at Michigan State University……...2010

"Grid School" four day program
Institute of Public Utilities at Michigan State University……...2011

"An Examination of RTO Capacity Markets"
Institute of Public Utilities at Michigan State University……...2011

"Electric Market Dynamics for Business Professionals……...2010
Mid-continental Independent System Operator

"Financial Transmission Rights"……..2011
Mid-continental Independent System Operator

"Auction Revenue Rights"…….2013
Mid-continental Independent System Operator

"Transmission Planning"……..…….2013
Mid-continental Independent System Operator

"Energy and Operating Reserves Markets"……2015
Mid-continental Independent System Operator

"Resource Adequacy"……...2015
Mid-continental Independent System Operator

"Market Settlements"…….2015
Mid-continental Independent System Operator

"New Market Changes"…….2015
Mid-continental Independent System Operator

Employment

August 2015 – present.Utility Economist, Minnesota Attorney General
2010-June 2015…….Advanced Economist, Public Service Commission of Wisconsin
2001-2010…… .Associate Professor, UW Colleges
2000-2001……..Assistant Professor, New Mexico Highlands University
1998-1997……..Senior Gas Supply Planner, Public Service Company of NM
1996-1997……..Economic Analyst, City of Albuquerque

Previous Testimony and Comments

Company	Docket No.	Subject
Northern States Power Company	M-15-808	GUIC Rider
CenterPoint Energy Resources	GR-15-424	CenterPoint Rate Case
American Transmission Company	5-CE-142	Transmission Line Application
Wisconsin Public Service Company	6690-CE-197	Pollution Control Application
Northern States Power Company	5-CE-136	Transmission Line Application
American Transmission Company	137-CE-161	Transmission Line Application
Wisconsin Power and Light	6680-EB-105	Power Plant Purchase

OAG No. 134

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition, page 28.

MERC states that "firm capacity was exceeded by 33,420 therms at TBS 1D, even after large customers were curtailed" on January 6, 2014. Provide the following information:

1. Were all non-firm customers called to curtail? Identify the number and usage of all customers that were not called to curtail.

2. Given that MERC exceeded its firm capacity, what happened to firm customers on January 6, 2014?

3. Was there any unauthorized use by non-firm customers on January 6, 2014? What steps has MERC taken to eliminate unauthorized use in the future?

4. Did MERC experience any capacity-related outages or other system issues on January 6, 2014?

RESPONSE:

1. No, only MERC's Large Volume Interruptible customers were called to curtail. Twenty-eight Small Volume Interruptible customers who are served by Rochester TBS 1B or 1D

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

were not called to curtail their usage on January 6, 2014. Based on available telemetry data, the daily usage of those Small Volume Interruptible customers on January 6, 2014 was 1,675 dekatherms.

2. Because curtailment of all Large Volume Interruptible customers addressed the capacity shortfall on January 6, 2014, none of MERC's firm customers' usage was affected that day.

3. Yes, unauthorized gas usage by Large Volume Interruptible customers after the curtailment was called did occur. As a result, MERC assessed curtailment penalties in accordance with its then-effective tariff provisions. Since that time, MERC has agreed to increase its curtailment penalty from $20 per dekatherm to $50 per dekatherm as part of its pending rate case, Docket No. G011/GR-15-736. Additionally, as a result of the curtailment, MERC engaged in conversations with its interruptible customers about obtaining additional firm capacity.

4. No, MERC did not experience any capacity-related outages or other system issues on January 6, 2014.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Nonpublic [ ]
Public [X]

Utility Information Request

Docket Number: G011/M-15-895

Date of Request: 3/16/2016

Requested From: Amber Lee
Minnesota Energy Resources Corp.

Response Due: 3/28/2016

Analyst Requesting Information: Adam Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[X] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
15	Subject: Sales Forecast Please update the Company's forecasting analysis using Rochester specific data weather data instead of the virtual weather station data used in the Company's original *Petition*. If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s). **MERC Response:** Please see the following Excel files: WeatherData_Rochester.xls ResAvgUse.xls SCIAvgUse.xls LCISales.xls IntSales.xls TransSales.xls ResAvgUse_Cal.xls SCIAvgUse_Cal.xls

Response by: David Clabots

Title: Senior Project Specialist

Department: Treasury Dept.

Telephone: 920-433-1355

List sources of information:

LClSales_Cal.xls
IntSales_Cal.xls
TransSales_Cal.xls

DOC-15 Rochester Gas pipeline Certification Revised with Rochester Weather.xls
DOC-15 Rochester Design Peak Day Analysis Revised with Rochester Weather.xls

Response by: David Clabots

Title: Senior Project Specialist

Department: Treasury Dept.

Telephone: 920-433-1355

List sources of information:

Name	Constant Intercept	AR(1) Variable	Peak AHDD	Point Estimate	Adjusted R Squared Factor	Standard Error Sigma	Confidence Level Factor for 97.50%	Peak Day Adj for Standard Error 2 Standard Deviations	105.00% Reserve Margin
Byron	69.407	22.074	101	2,299	0.9580	71.420	1.960	2,439	2,561
Claremont	14.210	2.747	101	292	0.9660	6.900	1.960	305	320
Dodge Center	235.133	17.473	101	2,000	0.9280	80.260	1.960	2,157	2,265
Kasson	106.281	31.575	101	3,295	0.9630	93.890	1.960	3,479	3,653
Kenyon	40.463	9.749	101	1,025	0.9570	31.030	1.960	1,086	1,140
Pine Island	40.142	14.391	101	1,494	0.9570	45.680	1.960	1,583	1,662
Wanamingo	69.244	5.553	101	630	0.9030	37.060	1.960	703	738
West Concord	28.398	4.857	101	519	0.9590	14.520	1.960	547	575
Zumbrota	-103.362	15.377	101	1,450	0.9370	103.770	1.960	1,653	1,736
Steele	6.913	1.250	101	133	0.7700	5.6100	1.960	144	151
Cannon Falls	305.726	25.888	101	2,920	0.9310	110.5500	1.960	3,137	3,294
Dover	10.790	3.018	101	316	0.9450	9.8100	1.960	335	352
Eyota	31.663	7.851	101	825	0.9560	24.8900	1.960	873	917
Viola	5.797	0.928	101	100	0.8800	1.8900	1.960	103	108
Stewartville	144.208	31.607	101	3,337	0.9580	100.6300	1.960	3,534	3,710
Hayfield	80.068	7.549	101	843	0.9440	27.2500	1.960	896	941
Blooming Prairie	218.207	12.324	101	1,463	0.9420	55.3900	1.960	1,571	1,650
Ellandale	29.296	4.233	101	457	0.9430	14.2600	1.960	485	509
Rochester 1D 1B	2104.081	539.618	101	56,605	0.9590	1716.3100	1.960	59,969	62,968
Totals	3436.665	758.062	101	80,001				85,001	89,251

Start with Point estimate
Add the standard error and 2 deviations
97.5% confidence the design day will be at or below column I

Projected Design Day Assuming 1.5% Annual Growth — Revised with Rochester Weather from 1.6% to 1.5%

	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%		
Winter Period	Byron	Claremont	Dodge Center	Kasson	Kenyon	Pine Island	Wanamingo	West Concord	Zumbrota	Steele	Cannon Falls	Dover	Eyota	Viola	Stewartville	Hayfield	Blooming Prairie	Ellandale	Rochester 1D 1B	Total	Current Firm Capacity	Projected Capacity Needed
2015/16	2,439	305	2,157	3,479	1,086	1,583	703	547	1,653	144	3,137	335	873	103	3,534	896	1,571	485	59,969	85,001	74,129	10,872
2016/17	2,475	310	2,190	3,532	1,102	1,607	713	556	1,678	146	3,184	340	886	105	3,587	909	1,595	492	60,869	86,276	74,129	12,147
2017/18	2,513	314	2,222	3,585	1,119	1,631	724	564	1,703	149	3,232	345	900	106	3,641	923	1,619	499	61,782	87,570	74,129	13,441
2018/19	2,550	319	2,256	3,638	1,136	1,655	735	572	1,729	151	3,280	350	913	108	3,695	937	1,643	507	62,709	88,884	74,129	14,755
2019/20	2,589	324	2,290	3,693	1,153	1,680	746	581	1,755	153	3,330	355	927	110	3,751	951	1,668	515	63,649	90,217	74,129	16,088
2020/21	2,627	329	2,324	3,748	1,170	1,706	757	590	1,781	155	3,380	361	941	111	3,807	965	1,693	522	64,604	91,570	74,129	17,441
2021/22	2,667	334	2,359	3,805	1,187	1,731	768	599	1,808	158	3,430	366	955	113	3,864	980	1,718	530	65,573	92,944	74,129	18,815
2022/23	2,707	339	2,394	3,862	1,205	1,757	780	608	1,835	160	3,482	372	969	115	3,922	994	1,744	538	66,557	94,338	74,129	20,209
2023/24	2,747	344	2,430	3,919	1,223	1,783	792	617	1,862	162	3,534	377	984	116	3,981	1,009	1,770	546	67,555	95,753	74,129	21,624
2024/25	2,789	349	2,467	3,978	1,242	1,810	803	626	1,890	165	3,587	383	999	118	4,040	1,024	1,797	554	68,568	97,189	74,129	23,060
2025/26	2,830	354	2,504	4,038	1,260	1,837	816	635	1,918	167	3,641	389	1,014	120	4,101	1,040	1,824	563	69,597	98,647	74,129	24,518
2026/27	2,873	359	2,541	4,099	1,279	1,865	828	645	1,947	170	3,695	394	1,029	122	4,163	1,055	1,851	571	70,641	100,127	74,129	25,998
2027/28	2,916	365	2,579	4,160	1,298	1,893	840	654	1,976	172	3,751	400	1,044	123	4,225	1,071	1,879	580	71,701	101,629	74,129	27,500
2028/29	2,960	370	2,618	4,222	1,318	1,921	853	664	2,006	175	3,807	406	1,060	125	4,288	1,087	1,907	588	72,776	103,153	74,129	29,024
2029/30	3,004	376	2,657	4,286	1,338	1,950	866	674	2,036	178	3,864	412	1,076	127	4,353	1,104	1,936	597	73,868	104,701	74,129	30,572
2030/31	3,049	382	2,697	4,350	1,358	1,979	879	684	2,067	180	3,922	419	1,092	129	4,418	1,120	1,965	606	74,976	106,271	74,129	32,142
2031/32	3,095	387	2,737	4,415	1,378	2,009	892	695	2,098	183	3,981	425	1,108	131	4,484	1,137	1,994	615	76,100	107,865	74,129	33,736
2032/33	3,141	393	2,779	4,482	1,399	2,039	905	705	2,129	186	4,041	431	1,125	133	4,552	1,154	2,024	624	77,242	109,483	74,129	35,354
2033/34	3,188	399	2,820	4,549	1,420	2,070	919	716	2,161	188	4,101	438	1,142	135	4,620	1,171	2,054	634	78,400	111,125	74,129	36,996
2034/35	3,236	405	2,863	4,617	1,441	2,101	932	726	2,194	191	4,163	444	1,159	137	4,689	1,189	2,085	643	79,576	112,792	74,129	38,663
2035/36	3,285	411	2,905	4,686	1,463	2,132	946	737	2,226	194	4,225	451	1,176	139	4,759	1,207	2,117	653	80,770	114,484	74,129	40,355
2036/37	3,334	417	2,949	4,757	1,485	2,164	961	748	2,260	197	4,289	458	1,194	141	4,831	1,225	2,148	663	81,982	116,201	74,129	42,072
2037/38	3,384	423	2,993	4,828	1,507	2,197	975	760	2,294	200	4,353	465	1,212	143	4,903	1,243	2,181	673	83,211	117,944	74,129	43,815
2038/39	3,435	430	3,038	4,900	1,529	2,230	990	771	2,328	203	4,418	472	1,230	145	4,977	1,262	2,213	683	84,460	119,714	74,129	45,585
2039/40	3,486	436	3,084	4,974	1,552	2,263	1,005	783	2,363	206	4,484	479	1,249	148	5,052	1,281	2,246	693	85,726	121,509	74,129	47,380
2040/41	3,539	443	3,130	5,048	1,576	2,297	1,020	794	2,399	209	4,552	486	1,267	150	5,127	1,300	2,280	703	87,012	123,332	74,129	49,203
2041/42	3,592	449	3,177	5,124	1,599	2,332	1,035	806	2,435	212	4,620	493	1,286	152	5,204	1,319	2,314	714	88,318	125,182	74,129	51,053
2042/43	3,646	456	3,225	5,201	1,623	2,367	1,050	818	2,471	215	4,689	501	1,306	154	5,282	1,339	2,349	725	89,642	127,060	74,129	52,931
2043/44	3,700	463	3,273	5,279	1,648	2,402	1,066	831	2,508	219	4,760	508	1,325	157	5,361	1,359	2,384	736	90,987	128,965	74,129	54,836

NNG Capacity	937	316	1,352	2,026	1,079	928	533	511	1,669	0.00	2,479	275	880	56	3,371	878	1,250	420	55,169	74,129

Projected Firm Capacity Requirements Assuming 1.6% growth

Winter Period	Byron	Claremont	Center	Kasson	Kenyon	Island	Wanamingo	Concord	Zumbrota	Steele	Cannon Falls	Dover	Eyota	Viola	Stewartville	Hayfield	Blooming Prairie	Ellandale	Rochester 1D 1B	Total
2017/18	2,513	314	2,222	3,585	1,119	1,631	724	564	1,703	149	3,232	345	900	106	3,641	923	1,619	499	61,782	87,570
2024/25	2,789	349	2,467	3,978	1,242	1,810	803	626	1,890	165	3,587	383	999	118	4,040	1,024	1,797	554	68,568	97,189
2033/34	3,188	399	2,820	4,549	1,420	2,070	919	716	2,161	188	4,101	438	1,142	135	4,620	1,171	2,054	634	78,400	111,125
2042/43	3,646	456	3,225	5,201	1,623	2,367	1,050	818	2,471	215	4,689	501	1,306	154	5,282	1,339	2,349	725	89,642	127,060

Projected Incremental Capacity Assuming 1.6% growth

Winter Period	Byron	Claremont	Center	Kasson	Kenyon	Island	Wanamingo	Concord	Zumbrota	Steele	Cannon Falls	Dover	Eyota	Viola	Stewartville	Hayfield	Blooming Prairie	Ellandale	Rochester 1D 1B	Total
2017/18	1,576	(2)	870	1,559	40	703	191	53	34	149	753	70	20	50	270	45	369	79	6,613	13,441
2023/24	276	35	244	394	123	179	80	62	187	16	355	38	99	12	400	101	178	55	6,786	9,619
2032/33	400	50	354	570	178	260	115	90	271	24	514	55	143	17	579	147	258	79	9,832	13,936
2041/42	457	57	404	652	204	297	132	103	310	27	588	63	164	19	662	168	295	91	11,242	15,934

Integrys Business Support, LLC
and its affiliates

Request for Proposal (RFP) 9000003194

Project Name:	Rochester Natural Gas Supply
Project Description:	Provide transmission pressure natural gas to the Rochester Minnesota area.
Location of Project:	Minnesota Energy Resources Company 1995 Rahncliff Ct Ste 200 Eagan, MN 55122-3401
Business Unit:	MERC - Minnesota Energy Resources Company
Project Number:	0140014005
RFP number:	9000003194
Date Issued:	December 31, 2014
Project Manager:	Jeff Krueger
Email Address:	JEKrueger@Integrysgroup.com
Phone Number:	(920) 433-5505
Cell Number:	(920) 680-5465
Buyer:	Carrie Voskuil
Bid Due Date:	January 16, 2015
Pre Bid Meeting:	N / A

1.0 Description of Work

Bidders shall provide the following information:

a. Overall cost associated with Scope outlined in Section 6.0 below

b. Overall schedule associated with Scope outlined in Section 6.0 below

c. Recurring operational & maintenance costs associated with Scope outlined in Section 6.0 below

It shall be the Bidder's responsibility to obtain complete information as to the regulatory filings and fieldwork involved in order to submit a complete and comprehensive proposal. It is understood that this proposal shall be non-binding in nature and is being used for indicative purposes and future contracting possibilities.

2.0 Schedule

The following milestone schedule shall apply to the work:

a. Natural Gas Transportation Capacity must be available no later than **August 1, 2017**

3.0 Applicable State Sales and Use Tax

Minnesota sales/use tax notice - -Do not bill sales/use tax. This purchase order covers material and/or labor which will enter into the construction, alteration, repair or improvement of real property. Minnesota sales or use tax for these materials is the responsibility of the contractor at the time of purchase by the contractor.

4.0 Special Requirements

N/A

5.0 Supplements, Standards, References and Drawings

Unless otherwise shown or specified, the work shall conform to the latest issue of all applicable standards and references.

- OSHA Safety and Workplace Standards
- United States Army Corps of Engineers
- Minnesota Public Utility Commission
- Minnesota Dept. of Environmental Quality
- Minnesota Dept. of Transportation
- Minnesota Administrative Code
- Olmstead County, MN County Administrative Codes
- City of Rochester MN Administrative Codes
- API Standard 1104 - Standard for Welding Pipelines, latest edition as approved by 49 CFR 192
- 49 CFR 192 - Code of Federal Regulations, Title 49, Part 192 Transportation of Natural & Other Gas by Pipeline

- ACI Standard 318 - American Concrete Institute - Building Code Requirements, latest edition
- ASTM D 448 – Standard Classification for Aggregate Sizes for Road and Bridge Construction.

6.0 Scope of Work

An outline of the work is provided in the following:

- OPTION 1:
  - Construct a Natural Gas Transmission pipeline that connects to a natural gas supply location of the bidders choosing and inter-connects to a new MERC TBS located on the northwest side of Rochester, Minnesota. Approximate location of the new MERC TBS is south of Hwy 14 but no further than 2,500 feet south of Country Club Road (CR-34) and 70th Ave SW.
  - Bid to include all inter-connection and routing design, easement acquisitions, regulatory and permitting requirements.
  - Construct the new pipeline for 100,000 Dth/day of firm capacity at 600psig minimum.
  - MERC to pay for the project over a minimum 25 year period in an agreed upon monthly rate.
- OPTION 2:
  - Work with the existing Natural Gas supply firm (Northern Natural Gas) to connect to their existing system at a location(s) of the bidders and NNG's choosing and inter-connects to the existing MERC Town Border Stations. TBS 1D is located on the northwest side of Rochester, Minnesota and TBS 1B is located on the Southeast of Rochester, Minnesota.
  - Bid to include all inter-connection and routing design, easement acquisitions, regulatory and permitting requirements.
  - Construct the inter-connections to allow for an overall incremental 45,000 Dth/day capacity at 600psig minimum over and above what is in service today. The split will be 80% of the new capacity (approx. 36,000Dth/day) to TBS 1D and 20% of the new capacity (approx. 9,00Dth/day) to TBS 1B.
  - MERC to pay for the project over a minimum 25 year period in an agreed upon monthly rate.
  - All inter-connect costs to be included in bid price.
  - Bidder will **own and operate** the newly constructed pipeline(s).
  - In both Options, MERC will provide and operate the regulation and odorization facilities for the gas into the distribution systems.

7.0 Proposal Price

Indicative price (+/- xx%) for complete work covered by these Bid Documents unless exceptions are specifically listed and identified as such in the proposal. Without limitation, it is understood that this price is indicative and is not subject to a Contract whether actual or assumed. This Request is being used for indicative purposes and possible future contracting needs.	**%**

8.0 Price Breakdown

Provide a breakdown of the indicative price for the following items (pricing breakdown is for evaluation and cost accounting only and cannot be used as a basis for adjustment in total indicative bid).

	Material	Labor
Option 1	$	$
Option 2	$	$
Totals	$	$

9.0 Price Adjustment

What is the error margin being used for the above prices? **(+ / - xx%)**

10.0 Change in the Work

As the project progresses, it may be necessary to include items of work not covered, or delete items covered, by this Indicative Bid. At no time will the Indicative Bid be subject to these additions or deletions. The Indicative Bid is a non-binding, one-time, stand-alone price (+/- xx%) being used for planning and future contracting possibilities.

11.0 Non Price Proposal Data

Is Bidder's price based on performing the work in accordance with the completion date set forth in the specification? **(Answer Yes or No)**
If answer above is no, Bidder shall indicate the schedule his proposal is based on.

Anticipated on-site construction period from mobilization to completion. **(How many months)**

12.0 Subcontractor Work

Bidder shall list any and all portions of the work to be subcontracted. Attention is specifically directed to the requirements set forth in the Agreement and Instructions to Bidders relative to subcontractors.

List Name of Subcontractor and Type of Work:
•
•
13.0 Safety Information
Safety Performance Information is required with submittal of this document and include information for subcontractors if applicable.
14.0 Conformity with Bid Documents
Bidder shall list all addendums that have been included in this proposal.
List Addendum Number and Date Issued:
•
•
Bidder hereby certifies that he agrees to all provisions of the Bid Documents and Addendums unless exceptions are specifically and clearly listed in a separate attachment to the proposal and identified as exceptions. Bidder's printed terms and conditions are not considered specific exceptions. Are any exceptions listed in Bidder proposal? **(Answer Yes or No)**
Signature of Bidder:
Print Name and Title of Bidder:
Bidding Company Name:

Date of Bid:	**Bid Validity Date:**

SCHEDULE 5
IS A NON-PUBLIC DOCUMENT
HIGHLY SENSITIVE TRADE SECRET INFORMATION
USE RESTRICTED PURSUANT TO HSTS ORDER IN
DOCKET NO. G011/M-15-895

DOCUMENTS MAY BE ACCESSED THROUGH
DOCKET NO. G011/M-16-315 PURSUANT TO HSTS ORDER IN
DOCKET NO. G011/M-15-895

SCHEDULE 6
IS A NON-PUBLIC DOCUMENT
HIGHLY SENSITIVE TRADE SECRET INFORMATION
USE RESTRICTED PURSUANT TO HSTS ORDER IN
DOCKET NO. G011/M-15-895

DOCUMENTS MAY BE ACCESSED THROUGH
DOCKET NO. G011/M-16-315 PURSUANT TO HSTS ORDER IN
DOCKET NO. G011/M-15-895

SCHEDULE 7
IS A NON-PUBLIC TRADE SECRET DOCUMENT
IN ITS ENTIRETY

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Nonpublic [ ]
Public [X]

Utility Information Request

Docket Number: G011/M-15-895 Date of Request: 4/29/2016

Requested From: Minnesota Energy Resources Corporation Response Due: 5/11/2016

Analyst Requesting Information: Adam Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
25	Subject: Capacity Contracts Reference: Mead Direct, Page 22, Lines 7-9 Please fully explain what days are unavailable to utilize the 20 percent of total Rochester firm capacity. If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s). MERC Response: The use of the 20% at alternate points would be on a secondary basis (aka alternate basis). This usage could be limited by Force Majeure, but also by group or point constraints outside of a Force Majeure. Priorities for group constraints are set forth in the NNG tariff. These priorities are as follows (in order of first allocated to last) – within each priority volumes are allocated on a pro-rata basis except for Interruptible which is allocated based on price:

Response by: Sarah R. Mead
Title: Manager of Gas Supply
Department: Gas Supply
Telephone: *920-433-7647*

List sources of information:

- Interruptible & Overrun
- Alternate Receipt to Alternate Delivery
- Alternate Receipt to Primary Delivery and Primary receipt to Alternate Delivery
- Primary Receipt to Primary Delivery (will not be allocated outside of Force Majeure)

The 20% would be subject to only Alternate Receipt to Alternate Delivery and Primary Receipt to Alternate Delivery.

As a practical matter, the availability of the 20% provides MERC a great deal of flexibility as the likelihood of Force Majeure and point constraints is relatively limited.

Response by: Sarah R. Mead

Title: Manager of Gas Supply

Department: Gas Supply

Telephone: *920-433-7647*

List sources of information:

OAG No. 155

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	March 1, 2016
Telephone:	(651) 757-1473	**Due Date:**	March 11, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Attachments C1-C18 and Appendix B and Appendix C, Petition, pp. 76–86.

1. Provide historical values for each of the forecasted variables for the past 30 years or the longest time series available.

   MERC Response:
   MERC only has data back to 2007, which corresponds to the time when MERC was purchased by Integrys from its prior owner, Aquila. All of the available data has been filed in this docket. MERC does not have access to reliable data from prior to this time, as has been described in various regulatory filings over the years. Please see response to number three below for additional background on the legacy data available to MERC.

2. Provide historical weather normalized annual total usage and for each customer class. Also provide total peak usage for each year. Provide for past 30 years or the longest time series available.

   MERC Response:
   MERC does not have weather normalized historical sales data for the specific Rochester area. MERC only has weather normalized historical data at the PGA level, i.e., NNG, Consolidated, and Albert Lea. MERC is currently working to compile weather normalized sales data specific to Rochester for the period 2007 through 2015 for the

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355

Residential, Small C&I, and Large C&I customer classes, and we will provide it as soon as it is available.

Regarding peak usage, generally MERC does not track peak usage by gate station for all customer classes. See MERC's response to OAG Information Request No. 121 for the ten highest utilization days since December 2012 for firm utilization at Rochester TBS 1B and 1D. MERC is working to compile peak one day throughputs for the period 2010-2015 for Rochester TBS 1B and 1D and will provide that information as soon as it is available.

3. Why were the forecast models based on only 7 years of data?

MERC Response:
Legacy Integrys acquired MERC from Aquila in 2006. All forecast data that existed prior to the acquisition had been the responsibility of Aquila.

In MERC's 2011 test year ratecase (MPUC Docket No. G007, 011/GR-10-977, OAH Docket No. 16-2500-21807-2) the DOC and the OAG raised a number of concerns with MERC's historical data. The OAG in Mr. Vincent Chavez's Rebuttal Testimony page 2 specifically raised concerns of "1. Combining three data sets (two pre-2007 Aquila data sets and one post-2007 data) in the regression analysis without a showing that the two data sets are substantively similar from either a practical or theoretical basis. 2. No verifiable billing cycle data prior to January 2007."Further, Mr. Chavez in bullet point number 7 on page 2 of his Rebuttal Testimony raised concerns about "Sales and Customer forecasts that cannot be replicated due to unreliable billing cycles data which contain large, negative sales values, negative customer counts, and mismatches in the number of billing cycles used for sales and customer counts."

As a result of issues such as these raised by the OAG and DOC, MERC stopped using any historical data from Aquila and rebuilt historical billing data from January 2007 forward in a new repository specifically for sales forecasting and regulatory filings. This database is now used for all sales forecasting purposes including budgeting, financial planning, ratecases, and gas supply plans, and was used to prepare forecasts for MERC's two most recent rate cases, Docket Nos. G011/GR-13-617 and G011/GR-15-736. MERC attempts to use consistent data across Dockets to provide consistent results.

4. Provide a definition, source and how each of the actual and forecasted values were derived in Attachment C14. How was the monthly GSP used in the forecast models derived? Describe what "Priori Information" was used for each of the forecasted variables. Provide an explanation of how each of these variables was derived. Provide a description of information from Mayo Clinic's Expansion Plan that was used to derive each the forecasted estimates including the values of any historical data and forecasted growth forecasts.

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355

MERC Response:
The data found in file C-14 is Rochester Economic and Demographic data from Moody's Analytics. Column C, representing Gross Metro Product data, was labeled "GSP" in order to quickly extract data with the MetrixND software.

GSP – Gross Metro Product
Emp – Total Employment
ManEmp – Manufacturing Employment
NonMan – Non-Manufacturing Employment. This is a calculated number of Total Employment minus Manufacturing Employment.
Pop – Population
Hsehlds – Number of Households
PPH – Number of People Per Household. This is a calculated number of Population divided by the Number of Households.
RPI – Real Personal Income

All the variables were forecasted by Moody's Analytics for the Rochester MSA. Please see the original file from Moody's Analytics for the data that was used – Excel file: Econ data Rochester.xls.

A Priori Information – No specific numbers were used in the regression models. No independent variable data from Moody's were adjusted due to this information. The *a priori* information was based on internal analysis and through discussions with MERC employees and management who have been and are involved with project. MERC did not rely upon any Mayo Clinic Expansion Plan document to derive its forecasts and does not have one in its possession.

As explained in our Petition and Appendix B, our forecasting process involved gathering *a priori* information regarding expected sales growth among our customer classes. This *a priori* information included internal MERC projections of potential customer usage and peak day requirements based on summary demographic data from the Rochester Olmsted Council of Governments ("ROCOG") 2040 Long Range Plan. A copy of the ROCOG and MERC data as referenced was provided as Attachment_OAG_154.pdf to MERC's response to OAG Information Request No. 154 and is included as an attachment to this response. This information was used to corroborate the reasonableness of the results of the forecast modeling. The comparison showed that the *a priori* information and statistical forecast modeling were consistent, both reflecting strong anticipated growth in demand over the next ten years.

5. Provide a copy of the Mayo Clinic's Expansion Plan including all the quantitative values assumed for all growth rates included in the plan and forecast models.

MERC Response:

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355

See MERC response to Part 4 above and MERC's response to OAG Information Request No. 154. MERC has no formal "Mayo Clinic Expansion Plan" document. As discussed in MERC's response to OAG Information Request No. 154, MERC used internal MERC projections of potential customer usage and peak day requirements based on summary demographic data from the Rochester Olmsted Council of Governments ("ROCOG") 2040 Long Range Plan to analyze the reasonableness of its forecasting model output. See Attachment_OAG_154.pdf, which is included as an attachment to this response.

6. Provide a copy of Moody's analytics (January 2015) cited in the discussion of Economic/Demographic Factors.

MERC Response:
Please see Excel file: Econ data Rochester.xls.

7. Describe the assumptions made on Rochester Residential and SC&I based on the Mayo Clinic expansion and economic growth in the Rochester area. Provide the values of any historical data and growth forecasts.

MERC Response:
MERC chose models that were on the robust side of valid statistical models to incorporate the growth of the expected impact from the Mayo Clinic expansion. There are no historical data or growth forecasts used outside of the Moody's data in the forecast models. *A Priori information* described above was also considered.

8. Why is there no Time Trend variable in the forecast equation for Residential Average Use?

MERC Response:
A Time Trend variable was not included in the development of the model. The model developed without this variable proved to be statistically valid in order to estimate Residential use per customer.

9. Provide the source and an explanation of how each of the following variables was derived:

C1: Provide all formulas and links to other worksheets. Where does the ResAvgUse and SCIAvgUse data come from? It appears that SCICust comes from C16 but the numbers for 2015 do not match.

MERC Response:

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355

In Attachment C_1_Rochester Annual Calendar Sales Forecast.xlsx, ResAvgUse and SCIAvgUse are derived by taking the annual sales divided by the annual customer counts for each respective class.

Please see Excel file: Attachment C_& Input Data and Customer Counts.xls. The first tab contains monthly billed sales by class the second tab contains monthly customer counts by class. MetrixND brings these numbers in and divides the monthly sales by the monthly customer counts by class to derive monthly Residential Average Use per Customer (ResAvgUse) and Small C&I Average Use per Customer (SCIAvgUse). Attachemnt C1_Rochester Annual Calendar Sales Forecast.xls provides the calendar forecasted results of the MetrixND regression models, which start with the monthly billing data, prepare a monthly billing sales forecast, then simulate a calendar forecast by switch out the billing degree days with calendar degree days. The annual average use-per-customer numbers are derived by taking total annual forecasted sales divided by the average annual number of customer counts. See Attachment C_5 Residential Calendar Average Use Per Customer Forecast.xlsx to see the monthly calendar forecasted Residential UPC. See Attachment C_6 SCI Average Use Per Customer Forecast.xlsx to see the monthly calendar forecasted SC&I UPC.

Attachment C_16 SCI Customer forecast model.xlsx contains monthly historical data through July 2015. SCICust for 2015 found in Attachment C_1 is an annual number made up of half historical customer counts and half forecasted customer counts.

C8: What is the source of historical and forecasted GSP and how was monthly and forecasted GSP derived?

MERC Response:
The variable name "GSP" represents Rochester Gross Metro Product ("GMP"), provided by Moody's Analytics.

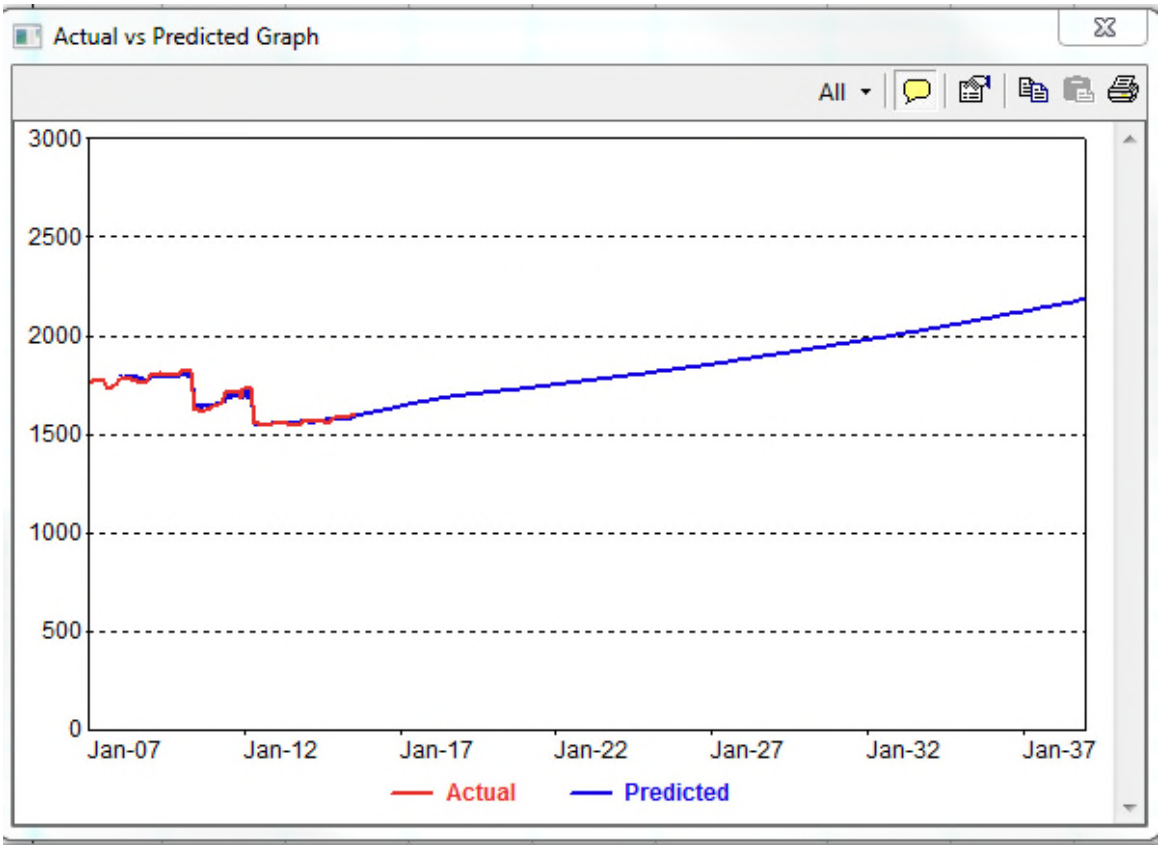
Moody's has informed us that:

> "The historical data for GMP comes from the U.S. Bureau of Economic Analysis which publishes a yearly release on gross product by metro area. Our data team converts the data into quarterly frequency for our forecasts.
>
> Forecasted GMP for Rochester is calculated similarly to the equation structure for states. Output is forecasted based on state-level GDP as well as the metro area's relative population and income growth compared to the state. A convergence term for relative per capita income is also included. Any conversions to different frequencies, such as monthly, are done using standard cubic spline conversion procedures."

C10: Explain the reasoning for the AftMay10 and AftApr12 variables.

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355

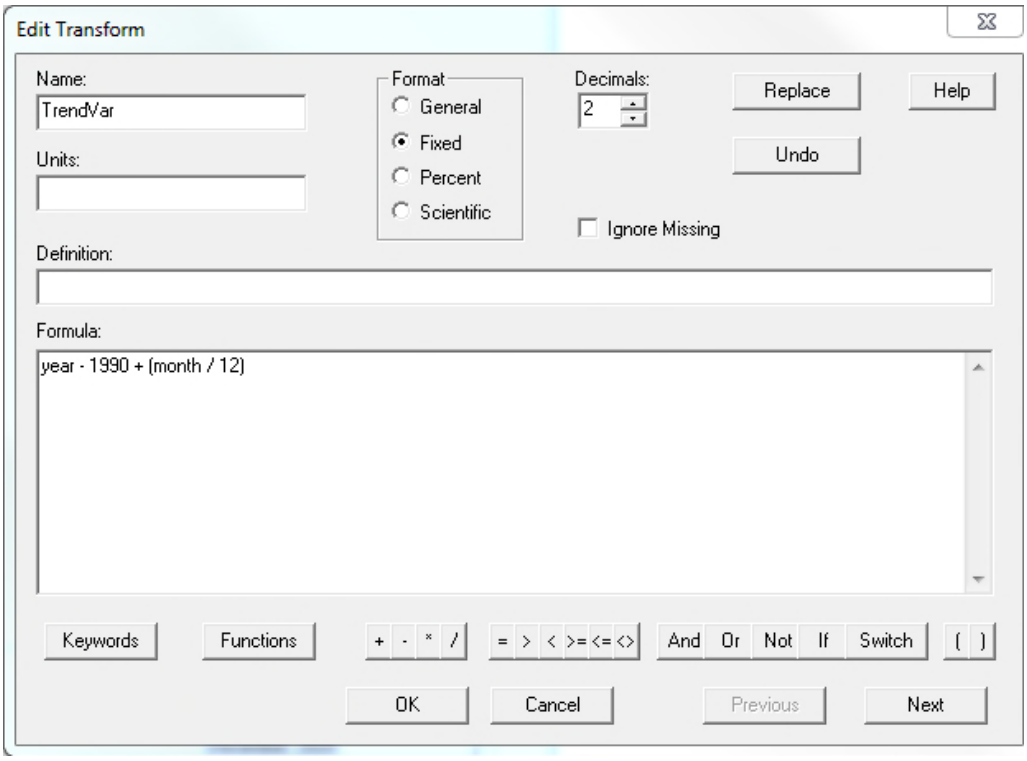
MERC Response:
If you graph the historical LC&I customer count data you will see significant step changes in the counts. These variables were added to account for these significant events. See table below.



C11: What does the TrendVar represent and how is it derived? What is the reasoning behind the Aft2014 variable?

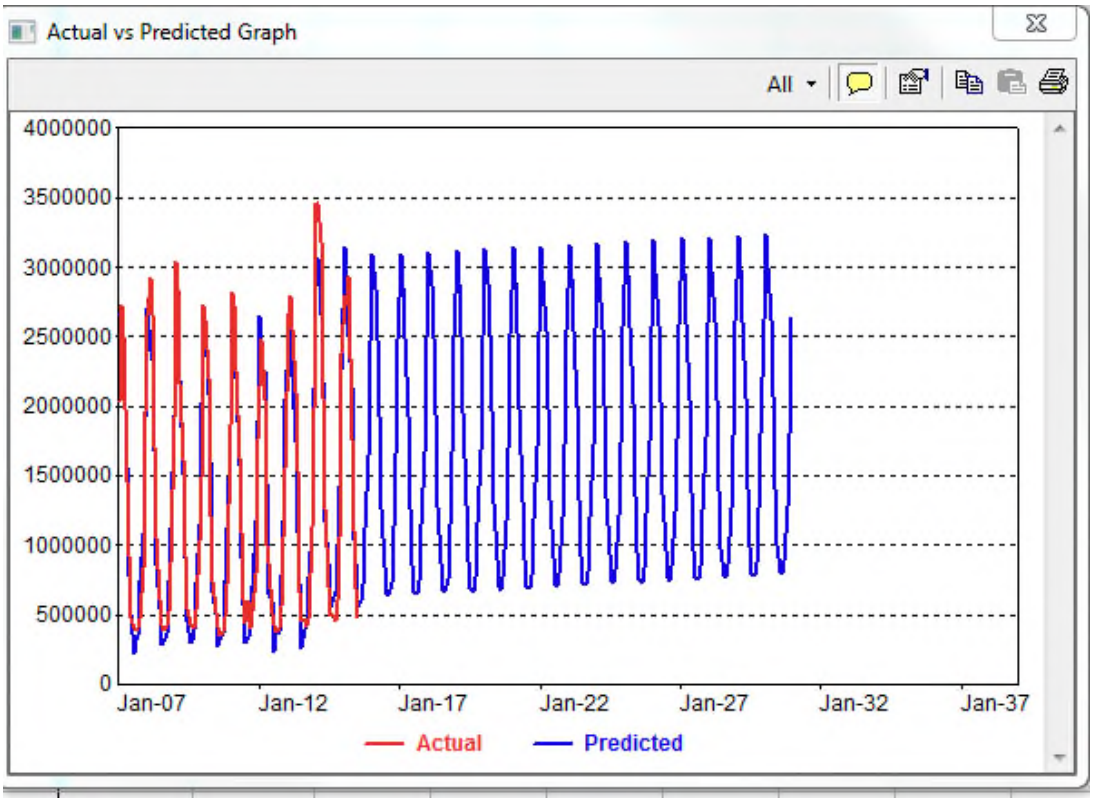
MERC Response:

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355



TrendVar is a monthly trend variable starting in 1990. See above table. The 2014 sales data was high compared to recent history. This variable was used to account for what may have been an unusual event, enabling us to forecast something more consistent with 2015 historical sales levels. See table below.

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355



C12: Explain the reasoning for the monthly dummy variables that were used?

MERC Response:
MERC used these monthly binary variables to help with seasonality issues.

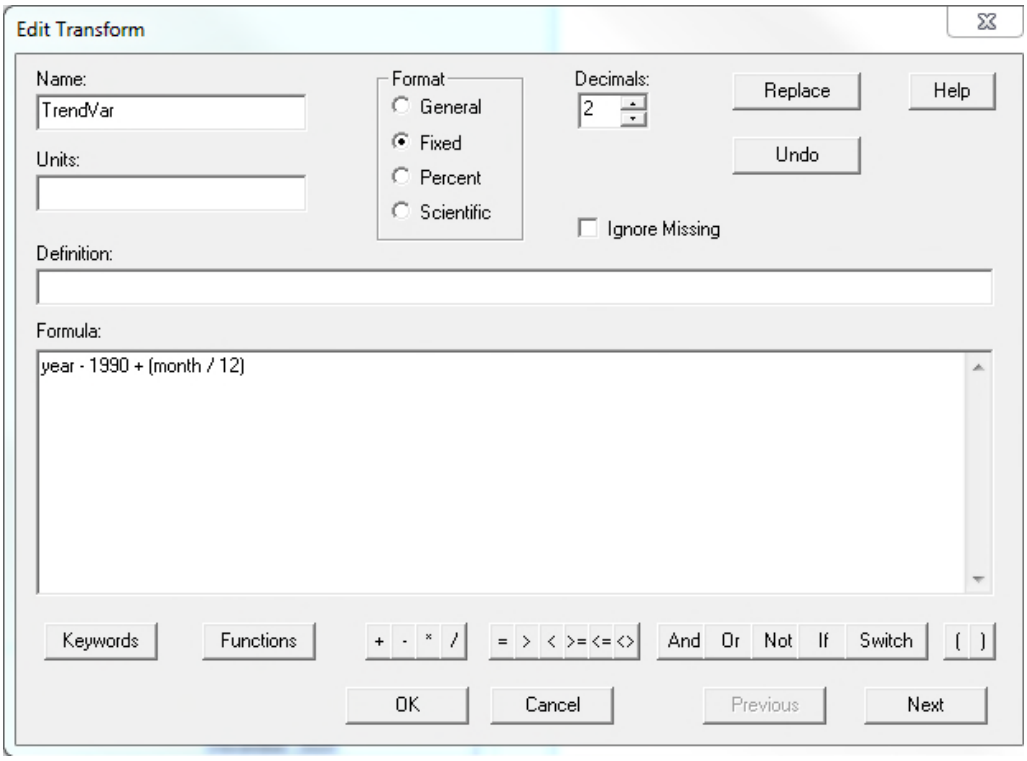
C13: Explain how the initial value of the TimeTrend variable was derived and what it represents.

MERC Response:
This is a monthly time trend of 1, 2, 3, 4, 5…. starting in January 1990 so in January 2007 when the sales data begins the monthly time trend value is 205.

C15: What does the TrendVar represent and how is it derived? What is the reasoning behind the Aft2014 variable?

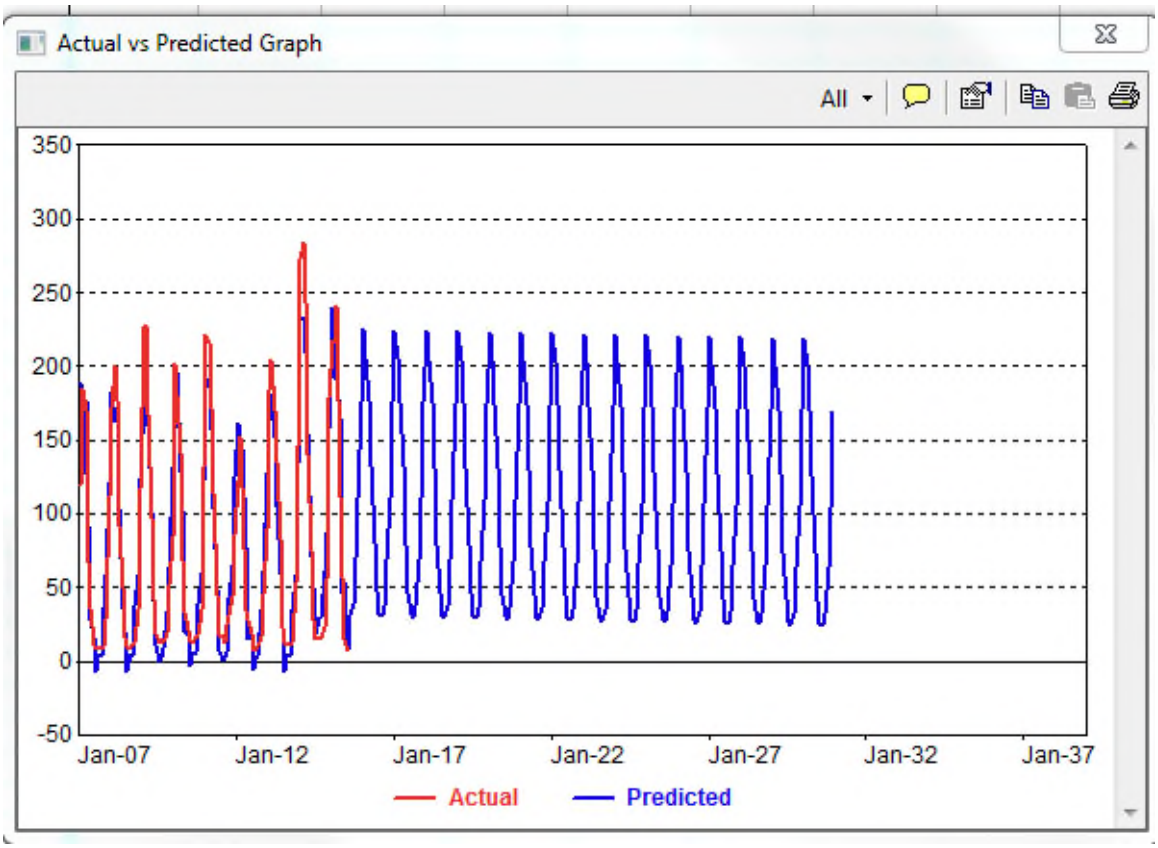
MERC Response:

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355



TrendVar is a monthly trend variable starting in 1990. See above table. The 2014 sales data was high compared to recent history. This variable was used to account for what may have been an unusual event, enabling us to forecast something more consistent with 2015 historical sales levels. See table below.

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355



C17: Explain the Transport Sales Forecast Model. How is the Transport variable defined? What units does it represent? How are the Simple, Trend and Seasonal variables derived? Provide Excel spreadsheets with formulas intact.

MERC Response:
Attachment C-17 is the Transport customer count model / forecast. Attachment C-18 is the Transport Sales forecast model / forecast. The Transport customer count model is an Exponential Smoothing Model. The units are customer counts. There are no Excel spreadsheets for this model. These variables are all defined within MetrixND.

MERC has included documentation in Attachment "Exponential Smoothing Methodology" from the Help section of MetrixND that describes the Exponential Smoothing Model in MetrixND and the Holt Winters specification that MERC used.

C18: Explain how the Customer Forecast is incorporated into the Sales Forecast. There is a variable in the spreadsheet called GSP. I assume that is gross state product. However the description of the Transport Sales Forecast Model in the Petition (p. 78) says that Gross Metro Product is used. Which is used, Gross Metro Product or Gross State Product? If Gross Metro

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355

Product, describe where this data comes from and how the monthly values are determined.

MERC Response:
Attachment C-18 is the Transport sales model / forecast. Attachment C-17 is the Transport customer count model / forecast. The Transport Sales model uses Gross Metro Product "GMP". When building the Rochester models MERC took an existing model framework, used the local Rochester data, but did not re-label the variable name in order to avoid having to recode MetrixND.

The GMP variable was forecasted by Moody's Analytics. Moody's creates the monthly variables by interpolating the quarterly data. See Excel file: Econ data Rochester.xls.

10. Were the Actual values in the YHat worksheet of each Forecast Workbook used for determining the pipeline capacity needs? If not, explain what value for each of the forecasted values was used to determine pipeline capacity needs and provide the annual values used to determine pipeline capacity needs.

MERC Response:
Yes. Please see Excel file: Rochester Design Day Peak Day Analysis Sept 2015 Regressions corrected for AutoCor.xlsx (attached); Tab "Regression Summary with AutoCor"; Top table. For each town boarder station the Constant and coefficients were used to determine the point estimate. Column C labeled AR(1) Variable is the summation of the weather coefficient and the AR(1) term. That coefficient was multiplied times the design day weather of 101 HDD to derive the point estimate. Each regression was based on daily historical data for the winter months of December, January and February for 2012 – 2015.

The bottom table projects the design day peak out over time based on the average growth rate for retail sales (excludes Interruptible and Transport) of 1.6%. See Excel file: This was used Rochester Gas pipeline Certification_Rochester MN (9-1-2015).xlsx (attached). See tab: Subp.3 B-Consumption and Cust. Cell N33 to find the average sales growth rate of 1.6% used in Excel file: Rochester Design Day Peak Day Analysis Sept 2015 Regressions corrected for AutoCor.xlsx; Tab "Regression Summary with AutoCor"; Bottom table. The annual sales used to determine the average growth rate are in Column N, Rows 22 – 32.

11. For each of the values in the tables on pages 83 - 87 provide the formulas and links to other spreadsheets (Attachments C1- C18).

MERC Response:
There are no formulas or links to other spreadsheets for the tables on pages 83-87. Please see Excel file: This was used Rochester Gas pipeline Certification_Rochester MN (9-1-

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355

2015).xlsx (attached). These numbers were cut and pasted from Excel file: NNG.xls and adjusted from Therms to Dekatherms. The file NNG.xls is the "report" file MetrixND exports the forecast to. See Tab "Monthly Sales" Rows 112 – 122. Note, here again the data contained in this file are for Rochester. The NNG.xls file along with the NNG MetrixND model framework were used for the Rochester models. MERC did not rename the files to save time recoding in MetrixND. The NNG model files were used but models were adapted accordingly for the Rochester data to get appropriate forecasts.

Attachments C1 – C18 are Excel files created by MetrixND to export the models, data used, and forecasts generated for documentation purposes.

Response by David Clabots
Title Senior Project Specialist
Department Forecasting
Telephone 920-433-1355

OAG No. 155.6

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:

David Kult

MPUC Docket No. G011/GP-15-895

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By: Ryan Barlow
Telephone: (651) 757-1473

Date of Request: May 12, 2016
Due Date: May 24, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Re: Response to OAG IR 155 Excel File Attachment "This was used Rochester Gas pipeline Certification _Rochester MN(9-1-2015) average forecasted sales growth rates 2016-2025"

Provide historical data for as far back as possible comparable to the forecasted data provided in the first tab or worksheet called "Subp.3 A-Annual Gas Consumption"

MERC Response:

Please see Excel file: OAG-155-6 Rochester Revised with Rochester Weather and historical data.xlsx. This is the same file that is referenced in MERC's Response to OAG IR No. 155.5 but has a revised sales forecast per MERC's Response to DOC IR No. 15. The Department requested the models be rerun using Rochester only weather data rather than the NNG purchased gas adjustment ("PGA") weighted weather.

Response by David Clabots
Title Senior Projects Specialist
Department Finance
Telephone 920-433-1355

OAG-155-6 Rochester Revised with Rochester Weather and historical data

Subp.3 A **Rochester Annual Gas Consumption by Ultimate Consumers**
Calendar Sales: Units MCF **Revised with Rochester weather**

Year	Residential	Small Commercial	Large Commercial	Interruptible	Transport	Total	
2007	3,365,431	83,859	1,469,313	344,164	3,852,379	9,115,146	
2008	3,705,225	95,485	1,613,473	348,392	3,459,702	9,222,277	1.2%
2009	3,526,467	101,010	1,499,955	339,559	3,955,371	9,422,362	2.2%
2010	3,374,777	99,720	1,426,417	292,372	3,974,689	9,167,975	-2.7%
2011	3,464,782	122,001	1,548,654	282,751	3,859,043	9,277,231	1.2%
2012	2,861,123	84,553	1,346,091	190,068	4,209,561	8,691,396	-6.3%
2013	3,824,179	147,097	1,760,247	268,506	3,817,202	9,817,231	13.0%
2014	4,238,355	190,538	1,971,412	183,544	4,383,211	10,967,060	11.7%
2015	3,713,977	180,305	1,871,935	208,100	4,243,211	10,217,528	-6.8%
2016	3,729,695	181,227	1,875,340	198,364	4,339,720	10,324,346	1.0%
2017	3,785,905	183,661	1,890,286	204,223	4,486,107	10,550,182	2.2%
2018	3,849,917	186,781	1,905,232	207,739	4,614,632	10,764,301	2.0%
2019	3,921,009	190,247	1,920,177	209,849	4,709,490	10,950,772	1.7%
2020	3,998,608	193,919	1,935,123	211,116	4,785,969	11,124,735	1.6%
2021	4,082,238	197,734	1,950,069	211,875	4,867,592	11,309,508	1.7%
2022	4,171,485	201,665	1,965,015	212,331	4,956,283	11,506,779	1.7%
2023	4,265,974	205,692	1,979,960	212,605	5,045,655	11,709,886	1.8%
2024	4,365,365	209,803	1,994,906	212,769	5,135,725	11,918,568	1.8%
2025	4,469,339	213,989	2,009,852	212,868	5,229,112	12,135,160	1.8%

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Nonpublic [ ]
Public [X]

Utility Information Request

Docket Number: G011/M-15-895

Date of Request: 3/16/2016

Requested From: Amber Lee
Minnesota Energy Resources Corp.

Response Due: 3/28/2016

Analyst Requesting Information: Adam Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[X] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
13	Subject: Sales Forecast Reference: Forecasting Data filed in *Reply Comments* Please fully explain why MERC included HDDs in the Transport model in Attachment C18 when this variable is not significant. If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s). **MERC Response:** After reviewing the model, MERC agrees that including the weather variable is in error because it is significantly not "statistically significant." MERC does have a number of transport customers that provide steam, etc. that are weather sensitive so weather is a variable that should be considered. See table below with the revised forecast.

Response by: David Clabots

Title: Senior Project Specialist

Department: Treasury Dept.

Telephone: 920-433-1355

List sources of information:

MERC Transportation Sales					
Rochester					
Annual Calendar Therm Sales					
	As Filed			Revised	
	w/HDD variable			w/o HDD Variable	
2015	42,435,734			42,435,169	
2016	43,390,911	2.3%		43,402,443	2.3%
2017	44,850,950	3.4%		44,869,106	3.4%
2018	46,133,187	2.9%		46,156,569	2.9%
2019	47,079,543	2.1%		47,106,782	2.1%
2020	47,842,535	1.6%		47,872,884	1.6%
2021	48,656,843	1.7%		48,690,511	1.7%
2022	49,541,673	1.8%		49,578,948	1.8%
2023	50,433,298	1.8%		50,474,207	1.8%
2024	51,331,883	1.8%		51,376,455	1.8%
2025	52,263,554	1.8%		52,311,922	1.8%

Response by: David Clabots
Title: Senior Project Specialist
Department: Treasury Dept.
Telephone: 920-433-1355

List sources of information:

PUBLIC DOCUMENT—TRADE SECRET DATA HAS BEEN EXCISED

OAG No. 107

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895
David Kult			
In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.			
By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

How much natural gas is currently used by Rochester Public Utilities? Describe any and all agreements with specificity, and provide a breakout of the natural gas usage by each Rochester Public Utilities generating asset that is served by MERC.

Produce all relevant documents, and any analysis in Excel format with all links and formulas intact.

RESPONSE:

MERC provides firm and transportation service to Rochester Public Utilities (RPU) through a number of metered accounts. In total (firm and transportation), RPU currently uses approximately **[TRADE SECRET DATA BEGINS…**
….TRADE SECRET DATA ENDS]. The table below provides a breakout for the annual average usage of each account. MERC notes that only the Silver Lake Plant and Cascade Creek Plant are generating assets. This customer usage information is designated as Trade Secret information as defined by Minn. Stat. §13.37, subd. 1(b). This information is not generally

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

PUBLIC DOCUMENT—TRADE SECRET DATA HAS BEEN EXCISED

known to and not readily ascertainable by vendors and competitors of MERC, who could obtain economic value from its disclosure.

Facility	Customer Class	Average Annual Usage
		[TRADE SECRET DATA BEGINS…
Silver Lake Plant	Transportation/Firm	
Cascade Creek Plant	Transportation	
Office/Warehouse	Firm	
Office/Warehouse	Firm	
Well Pump House	Firm	
Office	Firm	
Total Average Annual Usage (All Accounts)		
		…TRADE SECRET DATA ENDS]

]

As the table above shows, MERC provides transportation service to two generating assets owned by RPU—Silver Lake and Cascade Creek. RPU Silver Lake also currently contracts for a daily firm capacity**.**

Please see Attachment_OAG_107, which is the current agreement between MERC and RPU. This agreements is designated as Trade Secret in its entirety in accordance with Minn. Stat. §37.37, subd.1(b), and is nonpublic. The information contained in these agreements is not generally known to, and not readily ascertainable by vendors and competitors of MERC, who could obtain economic value from its disclosure.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

OAG No. 123

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

Has MERC discussed the possibility of a Combined Heat and Power plant with any entity that would be served by the Rochester Project, including the Mayo Clinic? Provide the details of any such discussion.

RESPONSE:

MERC currently serves one Combined Heat and Power (CHP) facility, the Franklin Heating Station, as described below.

Before filing the Petition in this matter MERC solicited the projected demand from our commercial, interruptible and transport customers within the Southeastern region of Minnesota. While the Mayo Clinic indicated they did not have any plans to invest in CHP facilities in the short-term, it is MERC's understanding that the Mayo Clinic is considering the construction of additional CHP facilities as part of the Destination Medical Center expansion.

The Franklin Heating Station, in operation since 1928, is owned in partnership between the Mayo Clinic and Rochester Methodist Hospital and has a CHP electric generating capacity of 11.75 MW. The Franklin Heating Station provides chilled water, soft tempered water, low and

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

high pressure steam and electricity to 25 downtown buildings in Rochester, Minnesota. Totaling over 8,000,000 square feet of floor space, the downtown properties include the Mayo Clinic, Rochester Methodist Hospital, Charter House and the Sunstone Corporation Hotel Properties. Since 1928, the plant has been constantly expanded and modernized over its life to increase capacity, improve reliability and efficiency to serve the needs of its customers.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

OAG No. 155.7-2

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:	**MPUC Docket No.** G011/GP-15-895
David Kult	
In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.	
By: Ryan Barlow	**Date of Request:** June 8, 2016
Telephone: (651) 757-1473	**Due Date:** June 20, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Re: OAG IR 155.7

What was the P-Value for the Real Personal Income coefficient?
What was the P-Value for the Time Trend coefficient?

MERC Response:

Using NNG weighted weather as filed in Petition:
P-Value for the Real Personal Income coefficient: 0.30%
P-Value for the Time Trend coefficient: 0.54%

Using Rochester weather:
P-Value for the Real Personal Income coefficient: 0.00%
P-Value for the Time Trend coefficient: 0.00%

Response by David Clabots
Title Senior Project Specialist
Department Finance
Telephone 920-433-1355

MERC Supplemental Response to OAG-155-7

Residential Forecast

Calendar Sales - Therms

Using NNG PGA Weather as filed in Petition

Rochester Filed					Rochester with Real Personal Income					Rochester with Time Trend				
	UPC		Total Sales			UPC		Total Sales			UPC		Total Sales	
2015	921		37,758,206		2015	890		36,497,573		2015	882		36,153,803	
2016	924	0.40%	38,398,050	1.70%	2016	882	-0.90%	36,642,836	0.40%	2016	866	-1.80%	35,985,212	-0.50%
2017	924	0.00%	38,978,354	1.50%	2017	877	-0.60%	36,993,028	1.00%	2017	860	-0.70%	36,269,862	0.80%
2018	924	0.00%	39,637,317	1.70%	2018	872	-0.50%	37,433,234	1.20%	2018	853	-0.70%	36,623,873	1.00%
2019	924	0.00%	40,369,173	1.80%	2019	870	-0.20%	38,038,454	1.60%	2019	847	-0.70%	37,036,286	1.10%
2020	923	0.00%	41,168,029	2.00%	2020	868	-0.20%	38,712,051	1.80%	2020	841	-0.70%	37,500,257	1.30%
2021	923	0.00%	42,028,989	2.10%	2021	866	-0.30%	39,416,352	1.80%	2021	835	-0.70%	38,010,024	1.40%
2022	923	0.00%	42,947,780	2.20%	2022	863	-0.30%	40,151,890	1.90%	2022	829	-0.70%	38,560,524	1.40%
2023	923	0.00%	43,920,557	2.30%	2023	860	-0.30%	40,920,413	1.90%	2023	823	-0.70%	39,147,195	1.50%
2024	923	0.00%	44,943,798	2.30%	2024	857	-0.40%	41,711,538	1.90%	2024	817	-0.70%	39,765,860	1.60%
2025	923	0.00%	46,014,241	2.40%	2025	853	-0.40%	42,519,320	1.90%	2025	811	-0.70%	40,412,671	1.60%
Average		0.04%		2.00%	Average		-0.41%		1.54%	Average		-0.81%		1.12%

* Rochester Residential UPC model as filed in Petition updated with Time Trend or Real Personal Income.

Using Rochester Weather

Rochester Filed					Rochester with Real Personal Income					Rochester with Time Trend				
	UPC		Total Sales			UPC		Total Sales			UPC		Total Sales	
2015	906		37,139,768		2015	891		36,551,543		2015	879		36,033,715	
2016	898	-0.90%	37,296,945	0.40%	2016	880	-1.30%	36,568,265	0.00%	2016	867	-1.30%	36,021,411	0.00%
2017	897	0.00%	37,859,048	1.50%	2017	876	-0.40%	36,974,076	1.10%	2017	862	-0.50%	36,376,822	1.00%
2018	897	0.00%	38,499,172	1.70%	2018	873	-0.40%	37,465,260	1.30%	2018	858	-0.50%	36,801,335	1.20%
2019	897	0.00%	39,210,091	1.80%	2019	872	-0.20%	38,094,957	1.70%	2019	853	-0.50%	37,286,894	1.30%
2020	897	0.00%	39,986,080	2.00%	2020	870	-0.20%	38,791,647	1.80%	2020	849	-0.50%	37,827,014	1.40%
2021	897	0.00%	40,822,382	2.10%	2021	868	-0.20%	39,526,772	1.90%	2021	844	-0.50%	38,416,246	1.60%
2022	897	0.00%	41,714,848	2.20%	2022	866	-0.20%	40,299,607	2.00%	2022	840	-0.50%	39,049,809	1.60%
2023	897	0.00%	42,659,743	2.30%	2023	864	-0.30%	41,110,416	2.00%	2023	835	-0.50%	39,723,390	1.70%
2024	897	0.00%	43,653,646	2.30%	2024	862	-0.30%	41,950,762	2.00%	2024	831	-0.50%	40,433,043	1.80%
2025	897	0.00%	44,693,392	2.40%	2025	859	-0.30%	42,815,487	2.10%	2025	826	-0.50%	41,175,127	1.80%
Average		-0.09%		1.87%	Average		-0.38%		1.59%	Average		-0.58%		1.34%

* Rochester Residential UPC model as filed in Petition updated with Time Trend or Real Personal Income.

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Nonpublic [ ]
Public [X]

Utility Information Request

Docket Number: G011/M-15-895

Date of Request: 3/16/2016

Requested From: Amber Lee
Minnesota Energy Resources Corp.

Response Due: 3/28/2016

Analyst Requesting Information: Adam Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[X] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
6	Subject: Sales Forecast Reference: Forecasting Data filed in *Reply Comments* Please fully explain the upward shift in sales between 2013 and 2014 shown in Attachment C2. If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s). **MERC Response:** The upward shift in sales between 2013 and 2014 as shown in Attachment C2 is primarily a result of two factors. First, the normal reclassification of customers between SC&I and LC&I each year based on usage. See table below of average customer counts. For 2012 and 2013, a number of customers moved from LC&I to SC&I. In 2014, some of those customers returned to LC&I. The second reason is due to the extreme cold weather in 2014.

Response by: David Clabots

Title: Senior Project Specialist

Department: Treasury Dept

Telephone: 920-433-1355

List sources of information:

Average Customer Counts				
	SC&I	LC&I	SC&I Diff	LC&I Diff
2011	1,197	1,693		
2012	1,313	1,598	116	-95
2013	1,370	1,556	57	-43
2014	1,381	1,568	12	13

Response by: David Clabots

Title: Senior Project Specialist

Department: Treasury Dept

Telephone: 920-433-1355

List sources of information:

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Nonpublic [ ]
Public [X]

Utility Information Request

Docket Number: G011/M-15-895

Date of Request: 3/16/2016

Requested From: Amber Lee
Minnesota Energy Resources Corp.

Response Due: 3/28/2016

Analyst Requesting Information: Adam Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[X] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
7	Subject: Sales Forecast Reference: Forecasting Data filed in *Reply Comments* Please fully explain what impacted sales in Attachment C10 between April 2010 and May 2010. If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s). **MERC Response:** Sales between April 2010 and May 2010 as reflected in Attachment C10 were impacted primarily by the normal reclassification of customers between SC&I and LC&I each year based on usage. See the table below of average customer counts. A number of customers moved from LC&I to SC&I. See Attachment C7 for the source of these numbers.

Average Customer Counts		
	SC&I	LC&I
April	1,058	1,815
May	1,224	1,624

Response by: David Clabots

Title: Senior Project Specialist

Department: Treasury Dept.

Telephone: 920-433-1355

List sources of information:

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Nonpublic [ ]
Public [X]

Utility Information Request

Docket Number: G011/M-15-895

Date of Request: 3/16/2016

Requested From: Amber Lee
Minnesota Energy Resources Corp.

Response Due: 3/28/2016

Analyst Requesting Information: Adam Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[X] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
8	Subject: Sales Forecast Reference: Forecasting Data filed in *Reply Comments* Please fully explain the shift in sales between 2013 and 2014 in Attachment C11. If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s). MERC Response: See MERC's response to Department Information Request No. 6 for a discussion of the factors affecting sales between 2013 and 2014. Attachment C11 is the model output of the LC&I billed sales forecast. Attachment C2 is the predicted LC&I billed sales forecast. Both Attachment C11 and Attachment C2 reflect a shift in sales from 2013 to 2014 caused for the same reasons discussed in MERC's response to Department Information Request No. 6.

Response by: David Clabots

Title: Senior Project Specialist

Department: Treasury Dept.

Telephone: 920-433-1355

List sources of information:

OAG No. 125

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

Has MERC had discussions with any entity within the Destination Medical Center Development District about increasing its natural gas usage?

RESPONSE:

Prior to filing its Petition in this matter, MERC discussed with a number of our commercial, interruptible, and transport customers within the Destination Medical Center ("DMC") Development District, including the Mayo Clinic, what they projected their potential energy demand would be over the short-term. At that time, no customer within the DMC Development District indicated any definitive plans regarding anticipated future natural gas usage.

Generally speaking, MERC anticipates the DMC will result in some increase in direct demand (i.e., from facilities within the DMC Development District) as well as more significant increases in indirect demand resulting from population and commercial growth driven by the DMC expansion.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

OAG No. 199

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	June 6, 2016
Telephone:	(651) 757-1473	**Due Date:**	June 16, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Provide all communications sent or received to the DMC and/or the City of Rochester regarding the proposed pipeline project. If MERC has communication with the DMC and/or the City beyond written communications, describe in detail the substance of the communication.

RESPONSE:

A summary of MERC's communications with the Destination Medical Center Corporation ("DMCC") and the City of Rochester ("City") regarding the proposed Rochester Natural Gas Pipeline Project ("Project") is provided below. Copies of the written communications are included with this response as Attachment_OAG_199.pdf.

First, MERC interprets this question as seeking information regarding the DMCC and the City's process for evaluating and funding public infrastructure projects and is targeted to obtain information as it pertains to MERC's efforts to interact with the DMCC and the City on this topic. As a result, MERC is not in this answer providing a comprehensive list of communications with the City of Rochester outside of its application to the DMCC and the City of Rochester for funding for the Project. MERC notes that it has area representatives in Rochester and that there is regular communication between those representatives and the City of Rochester on a wide range of topics, including the DMC effort by the City.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

Further, this response does not include communications with the Rochester Public Utilities ("RPU") regarding the Rochester Project. While MERC understands that RPU is technically part of the City of Rochester, for purposes of this response, MERC treats RPU as a separate entity. To MERC's knowledge, RPU is not involved with the DMC process. Please see MERC's response to OAG IR107, 108 and 156 for additional discussion on MERC's communications with RPU.

With that context, the following communications are responsive to this question:

On June 14, 2014, MERC sent a letter to the City of Rochester providing a brief description of the proposed Project and requested information that may assist in the routing, permitting, and design of the Project. A letter similar to the letter sent to the City is provided in Appendix A of the Route Permit Application for the Project filed on November 3, 2015 in Docket No. G-011/GP-15-858.

On January 20, 2016, MERC mailed the City of Rochester a copy of the Route Permit Application for the Project.

On February 15, 2016, counsel for MERC reached out via email to Mr. Mitchell Abeln, Finance Director for the DMC Economic Development Agency ("DMC EDA") for the purposes of obtaining contact information so the DMCC and the City of Rochester could be added to the service list for this proceeding. A copy of this email and Mr. Abeln's response is attached. This email was followed up with telephone calls in late February to describe the nature of this proceeding and to answer Mr. Abeln's questions about potential DMCC participation in this proceeding.

On April 12, 2016, counsel for MERC called Mr. Abeln, requesting a copy of the DMCC's Certification of Expenditures for 2015 that the DMCC submitted to the Department of Employment and Economic Development on April 1, 2016. A copy of this Certification was provided via email by Mr. Abeln later that day. A copy of this email is attached.

On April 15, 2016, MERC submitted an application to the DMCC and the City of Rochester requesting $5 million in funding for the Project. A copy of this application is attached.

Between April 27th and May 6th, 2016, counsel for MERC corresponded via email with Mr. Abeln and Cody Pogalz, Executive Assistant for the DMC EDA, regarding the status of MERC's application and setting up a meeting with the DMCC, the DMC EDA, and the City to discuss this application. Copies of these emails are attached.

On May 6, 2016, counsel for MERC called Mr. Abeln to confirm its availability for a May 18th meeting and to discuss the format and structure of the meeting.

On May 18, 2016, MERC met with representatives from the DMCC and the City of Rochester to discuss MERC's application for funding from the DMCC and the City. A copy of the PowerPoint presentation from that meeting is attached.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

On June 7, 2016, counsel for MERC called Mr. Abeln to follow-up on the May 18th meeting.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

From: Mitchell Abeln <mitchellabeln@dmceda.org>
Sent: Monday, February 15, 2016 1:33 PM
To: Krikava, Michael
Subject: RE: MERC Natural Gas Infrastructure Project in Rochester

Michael,

Thanks for wanting to include the DMC governing board. Let me speak with my executive director and confirm who would be most appropriate to added to the service list.

As background, the DMC Corporation consists of a eight board members (LINK). The non-profit DMC Economic Development Agency (EDA) is a private economic development corporation authorized by the DMC statute to provide services to the DMC Corporation. We (the EDA) also have our own private board.

I will be in touch soon-

Regards,

Mitchell Abeln, CFA, MBA
Finance Director
Destination Medical Center – Economic Development Agency
Email: mitchellabeln@dmceda.org
Work: 507.216.9725
Cell: 831.254.4491

From: Krikava, Michael [mailto:MKrikava@Briggs.com]
Sent: Monday, February 15, 2016 12:00 PM
To: Mitchell Abeln <mitchellabeln@dmceda.org>
Cc: Lee, Amber S <ASLee@minnesotaenergyresources.com>; Bailey, Koby <kabailey@integrysgroup.com>; Phillips, Kate <Catherine.Phillips@we-energies.com>
Subject: MERC Natural Gas Infrastructure Project in Rochester

Mitchell Abeln, CFA, MBA
Finance Director
Destination Medical Center – Economic Development Agency
Email: mitchellabeln@dmceda.org
Work: 507.216.9725
Cell: 831.254.4491

Dear Mr. Abeln:

I am counsel to Minnesota Energy Resources Corporation ("MERC") in connection with its proposed infrastructure project in and around the City of Rochester. I was given your contact information so that I could request your assistance in obtaining contact information for the Destination Medical Center ("DMC") governing board regarding a pending regulatory approval proceeding at the Minnesota Public Utilities Commission ("MPUC") pertaining to MERC's proposed Rochester Project.

The Rochester Project represents a significant and important investment to MERC that will have important impacts for the region and its constituents. The Rochester Project is subject to the review of the MPUC and MERC has commenced a proceeding before the MPUC seeking regulatory concurrence with the Project.

MERC wants to engage stakeholders, such as the DMC, in the regulatory review process. In addition, the MPUC has requested that the DMC governing board be added to the service list for the regulatory proceeding to ensure that the DMC is aware of the Project and can provide its perspective if it desires. Being added to the service list does not require that the DMC take any particular action but will ensure that the DMC is informed of the proceeding. For your information and convenience, I have attached the Notice for Hearing in that matter. Ordering paragraph 5 on page 8 of the Notice provides the MPUC's request that the DMC governing board be added to the service list.

I would appreciate it if you could advise me of the contact information for the appropriate individual(s) who could be added to the service list. As noted in the attached notice, the MPUC is interested in having the "governing board" of the DMC on the service list. As I am not familiar with the DMC corporate structure I would appreciate any guidance you could provide as to who should be included.

Please feel free to call or email if you have any questions.

Thank you in advance for your cooperation.

Very truly yours,

Michael C. Krikava
Briggs and Morgan
2200 IDS Center
80 South 8th Street
Minneapolis, MN 55402
T: 612-977-8566
F: 612-977-8650
C: 612-961-7138
E: Mkrikava@briggs.com

From: Mitchell Abeln <mitchellabeln@dmceda.org>
Sent: Tuesday, April 12, 2016 5:13 PM
To: Herring, Valerie
Subject: DMC Funding Report
Attachments: 12 Certification of Expenditures.pdf

Val,

Got your voicemail, attached is the annual certification letter that the DMCC submitted to DEED on April 1st. Is this what you are looking for? Let me know if you have any other questions.

Cheers,

Mitchell Abeln, CFA, MBA
Finance Director
Destination Medical Center – Economic Development Agency
Email: mitchellabeln@dmceda.org
Work: 507.216.9725
Cell: 831.254.4491

Certification of Expenditures
Destination Medical Center

For Calendar Year 2015
Due to Commissioner of Employment and Economic Development (DEED) by April 1

Pursuant to Minnesota Statutes, Section 469.47, the Medical Business Entity and the Destination Medical Center Corporation (DMCC) Board of Directors (assisted by the City of Rochester) respectively submit to the Department of Employment and Economic Development (DEED) the following expenditures that relate to the Destination Medical Center (DMC) Development for the calendar year **2015**, and the information required to support the approved methodology provided in the City of Rochester/Commissioner of Employment and Economic Development State Infrastructure Aid Agreement (State Infrastructure Aid Agreement).

Expenditures Reported This Year

Total Expenditure Reported This Year by Medical Business Entity[1]	$85,708,731
Total Expenditure Reported This Year for individuals and other private entities[1,2]	$20,487,686
TOTAL Expenditures This Year	$106,196,417

Cumulative Expenditures

Cumulative Previous Expenditures	$46,210,615
Previous Qualified Expenditures (minus $200,000,000 Required Initial Investment)	($153,789,385)
TOTAL Expenditures This Year (from above)	$106,196,417
Cumulative Qualified Expenditures as of 12/31/15	($47,592,968)

State Aid Qualified for this Year (local government match also required)

General State Infrastructure Aid Qualified for (Cum. Qual. Exp. multiplied by .0275)	
State Transit Aid Qualified for (multiplied by .0075)	

By providing my signature below, I certify that the information state herein, to the best of my knowledge, is accurate, true, and complies with the provisions of Minnesota Statutes, Section 469.47 and the approved methodology as outlined in the State Infrastructure Aid Agreement.

For Expenditures by the Medical Business Entity:

_____ _____
Mayo Clinic Chief Financial Officer Date

For all other Expenditures:

_____ _____
Destination Medical Center Corporation Date

1 Expenditures need to be after June 30, 2013
2 Private expenditures for the period of July 1, 2013 - December 31, 2015, after adoption of the Development Plan. Certain additional expenditures for this time period are currently under discussion with DEED, and may be included in the certification for calender year 2016.

Minnesota Energy Resources Corporation
Suite 200
1995 Rahncliff Court
Eagan, MN 55122
www.minnesotaenergyresources.com

April 15, 2016

Destination Medical Center Corporation
c/o DMC EDA Office
195 South Broadway
Rochester, MN 55902
Attn: Mitchell Abeln

RE: Application for Funding for the Rochester Natural Gas Extension Project

Dear Mr. Abeln:

Enclosed is an application for funding from the Destination Medical Center Corporation (DMCC) and the City of Rochester by Minnesota Energy Resources Corporation for the Rochester Natural Gas Extension Project (Project). Minnesota Energy Resources respectfully requests consideration of funding in the amount of five million dollars ($5,000,000) to offset the costs of certain aspects of the Project and the necessary expansion of the natural gas system in and around the City of Rochester to support current and projected future customer demands.

Minnesota Energy Resources is the sole provider of natural gas services to Rochester and the surrounding local communities. Rochester has experienced continued population growth over the last eight years and is poised to continue robust and even accelerating growth, in large part due to the expanding health care facilities associated with transforming the Mayo Clinic into a Destination Medical Center (DMC). As a result of this growth, the natural gas transmission pipeline and distribution systems in the Rochester area are operating at capacity and Minnesota Energy Resources' ability to provide firm and reliable natural gas service to new and existing customers is limited.

A critical component of the success of the DMC is adequate utility infrastructure to support the anticipated economic and population growth that the development of the DMC will spur in Rochester and the surrounding areas. Minnesota Energy Resources forecasts that the customer demand growth will increase our customer base in the Rochester area by approximately 20 percent over the next ten years. The proposed Project will expand the capacity of the natural gas distribution system in and around Rochester and will enable it to meet the needs of both its existing and new customers.

Through the Rochester Project, Minnesota Energy Resources and its customers are investing approximately $100 million to upgrade the natural gas infrastructure to provide additional natural gas capacity to facilitate anticipated residential and

commercial growth in and around Rochester. The Rochester Project is proceeding in two phases. In Phase I, Minnesota Energy Resources implemented $5.6 million of upgrades to the Rochester distribution system and in Phase II, Minnesota Energy Resources will implement an additional $44 million of system upgrades around Rochester to improve service to this growing community. In addition, upgrades to the Northern Natural Gas interstate pipeline into Rochester will require another approximately $60 million of capital investment. The $5 million funding requested from the DMCC represents only five percent of the overall cost being borne by Minnesota Energy Resources' customers.

Minnesota Energy Resources will pay the application fee to cover estimated administrative costs of the evaluation process for its application once this fee is determined by the DMCC and the City of Rochester.

A. The Rochester Natural Gas Pipeline Project

To meet the projected increase in demand for natural gas in and around Rochester, the capacity of both the interstate transmission pipeline system in the Rochester area and Minnesota Energy Resources' Rochester distribution system must be expanded. There are two primary reasons why the Minnesota Energy Resources system needs to be expanded to support the growth envisioned by the DMC plan.

First, to meet the increasing customer demands for natural gas, there must be transmission pipeline upgrades to increase the availability of natural gas to Minnesota Energy Resources' distribution system. Northern Natural Gas is the sole existing provider of interstate natural gas pipeline capacity to the Rochester area. To provide the necessary firm capacity, Northern Natural Gas will increase the capacity of its interstate pipeline transmission system in Southeastern Minnesota pursuant to a new long-term capacity contract that will ensure adequate gas capacity in the Rochester area for the next 25 years or more. The contract commits Northern Natural Gas to making the infrastructure upgrades necessary to provide Minnesota Energy Resources natural gas at volumes sufficient to meet the projected growth in demand. Northern Natural Gas' estimated capital investment for its work is approximately $60 million.

Second, to accommodate the capacity increase from Northern Natural Gas, Minnesota Energy Resources' distribution system must be upgraded and expanded to allow gas to be efficiently delivered to Rochester area customers. These upgrades and expansions will be completed in phases. Phase I of the Project involved modernizing and standardizing Minnesota Energy Resources' fractionated distribution system in the Rochester area. Phase I was substantially completed in 2015 at a cost of $5.6 million.

Phase II of the Project includes a 14-mile long main distribution pipeline that connects a rebuilt Town Border Station (TBS) in northwest Rochester to a new TBS in west Rochester to a new district regulator station in southeast Rochester. The cost of Phase II is estimated to be $44 million, and begins in 2017 with a projected completion

date of 2022. A figure illustrating the components and location of Phase II of the Project is included with the application.

Minnesota Energy Resources will use any funds from the DMCC or the City of Rochester to offset Project construction costs. This is analogous to a new gas utility customer making a "contribution in aid of construction" or "CIAC" to contribute to the cost of a utility construction project. A CIAC-type payment by the DMCC and City of Rochester is appropriate in this circumstance as Minnesota Energy Resources' work on the system will facilitate the expansion of the system to accommodate the growth envisioned by the DMC Plan.

Minnesota Energy Resources recognizes that the proposed Project is not explicitly included in the current DMC Development Plan and that most of the proposed new facilities are not located within one of the six DMC Development Districts. While Phase I was work inside Rochester, it generally was not located within the Development Districts. And Phase II is work generally outside of Rochester, although it is expressly designed to benefit Rochester. Nevertheless, these infrastructure improvements are essential to ensure that adequate firm natural gas service can be made available to the developers who will be constructing office buildings, residential buildings, medical facilities, and associated infrastructure within the DMC Development Districts. Thus, to the extent deemed necessary, Minnesota Energy Resources respectfully requests an amendment to the DMC Plan and the DMC Development Districts pursuant to Minn. Stat. § 469.43, subd. 4, to allow DMCC and the City of Rochester to assist with funding for this important public infrastructure project.

B. Application for Public Infrastructure Funding

Attached to this letter is Minnesota Energy Resources' Application for Public Infrastructure Funding which provides additional information about Minnesota Energy Resources' proposed Project. This Application utilizes the form provided in Appendix 11 of the DMC Development Plan.

C. Evaluation Criteria

In addition to the application and required supporting documentation, Section 3 of the DMC Development Plan provides a list of evaluation criteria that will be used by the DMCC and the City of Rochester in assessing whether to fund public infrastructure projects. Listed below are the six evaluation criteria outlined in Section 3 and a brief explanation of how the proposed Project meets the specified criteria.

(1) Does the project include a plan for achieving the DMC vision, goals, and objectives?

Yes.

As stated above, the success of the DMC depends on adequate infrastructure to support the robust growth that Rochester and the DMCC is predicting to arise out of the

DMC Plan. Minnesota Energy Resources' Rochester Natural Gas Extension Project is precisely the type of infrastructure that will be critical to the long-term success of the initiative.

Without the additional distribution capacity provided by the Project, Minnesota Energy Resources cannot meet the growth in demand for natural gas from existing or new customers in the Rochester area. The Project will ensure that upgraded and new facilities are in place to meet the growth in the demand that will result from the development of the DMC.

(2) Does the project include a plan for achieving consistency with the Development Plan (and any updates thereto) and other relevant planning documents?

Yes.

The project is consistent with the DMC Development Plan in that it provides the necessary natural gas infrastructure to support growth and continued investment in the DMC Development Districts as well as Rochester and the surrounding communities.

(3) Does the project include a plan that is financially viable?

Yes.

Minnesota Energy Resources, an operating subsidiary of WEC Energy Group, Inc., is a public utility under the jurisdiction of the Minnesota Public Utilities Commission. Minnesota Energy Resources has been providing natural gas service for over 80 years and currently serves approximately 230,000 customers in 184 communities across Minnesota. Minnesota Energy Resources is the sole natural gas utility in Rochester and many of the surrounding communities.

Minnesota Energy Resources' utility rates and practices are closely monitored and Minnesota Energy Resources operates in a fiscally responsible manner consistent with all utility accounting and service requirements. Minnesota Energy Resources will construct, own, and operate the proposed natural gas distribution upgrades. Minnesota Energy Resources is an investor-owned utility headquartered in Eagan, Minnesota. Minnesota Energy Resources' parent corporation is WEC Energy Group, Inc. from Milwaukee, Wisconsin. The WEC Energy Group utilities collectively serve 4.4 million electric and gas customers in Minnesota, Wisconsin, Illinois, and Michigan.

(4) Is the project consistent with the adopted strategies and/or one or more projects for the current implementation phase of the DMC Initiative?

Yes.

The project is a needed infrastructure project that will provide the backbone support for future development in and around Rochester. Minnesota Energy Resources' proposed Project and the DMC funding we seek is fully consistent with the DMCC's adopted strategies and is a necessary element to the success of many of the projects being contemplated by the DMC initiative.

For example, there are a number of new real estate developments being launched in and around the downtown area. It was recently announced that a $138 million project on the southeast corner of Broadway and Center Street is about to begin construction. This project will include a hotel to accommodate visitors to the City and Mayo Clinic, as well as significant retail space. This new space will require the availability of significant natural gas utility service.

In addition, a number of the older buildings in downtown Rochester are scheduled to be rehabilitated or replaced. There are plans to reuse the historic Chateau Theatre and a number of the older retail buildings, such as the former Michael's Restaurant, are slated to be rehabilitated and potentially expanded. This new and revitalized commercial and hotel development will all require the availability of significant natural gas utility service.

Yet another example is the proposed construction of a waterfront district near the Zumbro River. That project will include residential and retail space, much of which will be dependent upon reliable and adequate natural gas service.

Finally, the DMC Plan states that the initiative is projected to create 35,000 to 45,000 jobs over the next 20 years. Most of those jobs will occur within Minnesota Energy Resources' service territory. And many of the new employees will live in and around Rochester in the communities served by Minnesota Energy Resources.

All of this new activity will be heavily dependent upon having adequate and reliable natural gas service. Minnesota Energy Resources is well-positioned to assist the DMCC in achieving its goals by ensuring that adequate natural gas service is available to meet the heightened demand that will result from the success of the DMC initiative.

(5) Does the project include a plan for achieving Local Business, S/M/WBE Project Requirements and other project requirements?

Minnesota Energy Resources is a strong proponent of local economic development as a healthy local economy translates into a healthy gas utility. Minnesota Energy Resources generally bids out construction projects and anticipates continuing this practice when implementing the Rochester Project.

(6) Does the project include a plan to comply with or support the economic-fiscal goals and objectives of the DMC Initiative?

Yes.

The proposed Project will provide economic benefits to Rochester and the surrounding area. Economic benefits to the local economy will be realized during construction of the Project due to the influx of labor workforce and procurement of construction-related materials and supplies. These benefits will include material expenditures, workforce lodging, fuel sales, grocery sales, and restaurant expenditures. Additional local economic benefits include easement payments, permit fees, and property tax revenues. Also, construction of the Project will create temporary jobs for both local and non-local workers.

D. Conclusion

Minnesota Energy Resources respectfully requests that the DMCC review the enclosed application and supporting information and approve this Project for funding of five million dollars ($5,000,000) from DMC funds. The additional natural gas capacity provided by this Project is necessary infrastructure to meet the needs of existing customers in the Rochester area and the new customers that are anticipated as a result of development of the DMC. If you have any questions, please don't hesitate to contact me at 651-322-8903.

Sincerely yours,

David G. Kult
Vice President, Operations
Minnesota Energy Resources Corporation

Enclosures

DMC
A Global Destination for Health & Healing

APPLICATION FOR FUNDING OF PUBLIC INFRASTRUCTURE PROJECT

Return to: Destination Medical Center Corporation
c/o Destination Medical Center Economic Development Agency

General Information

Name of Applicant:	Address:
Minnesota Energy Resources Corporation (MERC)	1995 Rahncliff Court, Suite 200, Eagan, MN 55122

Contact Person

Name:	Title:
Amber Lee	Regulatory and Legislative Affairs Manager

Tel #:	Fax #:	Email:
651-322-8965	920-272-4000	aslee@minnesotaenergyresources.com

Type of Entity (check one)

☒ Corporation ☐ Partnership ☐ Sole Proprietorship ☐ Public Entity

State of Incorporation or Organization: Delaware

Nature of Business (attached additional materials, if available):
MERC delivers natural gas to 231,000 customers in 184 communities across Minnesota, including Rochester.

Project Team / Consultants

Architectural Firm:		**Engineering Firm:**	
Contact Person: N/A		Contact Person: Lindsay Lyle	
Address:		Address: 1995 Rahncliff Court, Suite 200, Eagan, MN 55122	
Tel #:	Fax #:	Tel #: 651-322-8909	Fax #: 920-272-4000
Email:		Email: lklyle@minnesotaenergyresources.,com	
General Contractor: Not yet selected.		**Legal Counsel:** Briggs and Morgan, P.A.	
Contact Person: MERC will select a General Contractor based on a competitive bid process.		Contact Person: Michael Krikava	
Address:		Address: 2200 IDS Center, 80 South 8th Street, Minneapolis, MN 55402	
Tel #:	Fax #:	Tel #: 612-977-8566	Fax #: 612-977-8650
Email:		Email: mkrikava@briggs.com	
Accounting Firm:		**Financial Adviser:** N/A	
Contact Person: Seth DeMerrit		Contact Person:	
Address: 700 North Adams Street, P.O. Box 19001, Green Bay, WI 54307-9001		Address:	
Tel #: 920-433-2926	Fax #:	Tel #:	Fax #:
Email: ssdemerritt@integrysgroup.com		Email:	

Marketing Consultant:	
Contact Person: Amber Lee	
Address: 1995 Rahncliff Court, Suite 200, Eagan, MN 55122	
Tel #:	Fax #: 920-272-4000
Email: aslee@minnesotaenergyresources.com	

Project Information

Name of Project: Rochester Natural Gas Pipeline Project

Location/Address: See Exhibit A.

1. Location

Attach (and label Exhibit A) information which fully describes and illustrates the location and boundaries of the proposed project. Include map(s), legal description(s), property identification numbers, addresses and area (in sq. ft. or acres).

The location of the Project is shown on Exhibit

2. Ownership and Legal Structure

Attach (and label Exhibit B) the full name(s) of the entity(s) which will own the project, and fully describe their legal structure (i.e. principals, ownership interests, liability, relationship to parent organization, subsidiaries, etc). If available provide federal and state tax ID #s.

3. Zoning and Planning Analysis

Attach (and label Exhibit C) information which describes the current and proposed zoning, variances required, property consolidations or subdivisions, etc.

4. Estimated Project Costs:

Land Acquisition	$
Site Development	
Building Cost	
Equipment	
Architectural/Engineering Fees	
Legal Fees	
Financing Costs	
Broker Costs	
Contingencies	
Other (specify)	
Total Costs	$ See Exhibit E

5. Sources of Financing

Developer Equity	$
Bank Loan/Private Financing Institution	
Public Infrastructure Funding	
Other	See Exhibit E
Total Sources	

6. Market Value

Total current market value prior to construction: $

Total estimated market value at completion: $ 100 million

What will the estimated real estate taxes of the project be upon completion? Please respond and include your calculations on the lines provided below:

Requested Funding

Amount of requested DMC Funds: $5 million

Purpose of requested DMC Funds: To construct the Rochester Natural Gas Pipeline Project.

If DMC Funds are not provided, will the project (1) proceed as previously described utilizing other financing, (2) proceed in some alternative form, or (3) not proceed at all? If project will proceed in some alternative form, provide a summary below: MERC is a rate regulated public utility. It receives funds from its ratepayers in the form of utility rates and applies those funds to the work the utility undertakes.

Other requested public financial assistance (federal, state or local): To the extent that MERC needs to finance major capital projects, it typically places private financing. At this time, MERC has not determined whether or how it will finance the Rochester Project.

Project Construction Schedule

Anticipated Construction Start Date: 2016

Construction Completion Date: 2023

If a phased project:

Phase Designation	% Completed	By Year
Rebuild of TBS 1D	100	2017
TBS 1 to TBS pipeline	100	2019
TBS to DRS pipeline	100	2022

Describe expected general traffic impacts of the project, including (but not limited to) on and off street parking, projected auto/truck counts, traffic flow, peak traffic periods, etc. There will be very limited traffic impacts due to this project. Any road crossings will be constructed via boring and any open excavations will be completed during the night hours and re-filled during the day. MERC will abide by all Minnesota Department of Transportation requirements and other permit requirements.

DMC
A Global Destination for Health & Healing

DEVELOPMENT PLAN
DESTINATION MEDICAL CENTER
DRAFT

Current and Projected Employment

Indicate below how many new jobs will be **created** by the project:

Type	Number of Jobs Created	Average Hourly Wage	Benefits
Professional/Managerial	FT: 0	$	
	PT: 0	$	
Technical/Skilled	FT: 0	$	
	PT: 0	$	
Unskilled/Semi-skilled	FT: 0	$	
	PT: 0	$	

Indicate below how many existing jobs will be **retained** by the project:

Type	Number of Jobs Created	Average Hourly Wage	Benefits
Professional/Managerial	FT: 0	$	
	PT: 0	$	
Technical/Skilled	FT: 0	$	
	PT: 0	$	
Unskilled/Semi-skilled	FT: 0	$	
	PT: 0	$	

Financial Information

Have "you" personally, or your entity or any entities managed or controlled by you ever filed for bankruptcy?

☐ YES ☐ NO If yes, provide details on separate sheet.

Have "you" personally, or your entity or any entities managed or controlled by you ever defaulted on any bond or mortgage commitment?

☐ YES ☐ NO If yes, provide details on separate sheet.

Have you applied for conventional financing for the project?

☐ YES ☒ NO If no, explain why; if yes, provide details on a separate sheet.

MERC is a rate regulated public utility. It receives funds from its ratepayers in the form of utility rates and applies those funds to the work the utility undertakes. To the extent that MERC needs to finance major capital projects, it typically places private financing. At this time, MERC has not determined whether or how it will finance the Rochester Project.

List financial references (include contact person and phone #)

Reference	Phone Number
N/A	

Additional Project Information Required for Application *[if necessary]*

1. Description

   Attach (and label **Exhibit D**) a complete description of the proposed project. If the project will proceed in phases, then provide information for each phase as well as the total project. Minimally, provide the following information:

   a. Do you have control of the project site? Explain in detail.
   b. Details of all known or suspected environmental issues with the site. Has any testing been completed or is underway?
   c. Type of project (retail, office, industrial, rental housing, home ownership, etc.)
   d. New construction or rehabilitation/renovation. If renovation, provide details.
   e. Description of structure which will need to be demolished.
   f. Description of owners/tenants who will need to be relocated.
   g. Details of any historic preservation designations and/or related issues.
   h. For commercial/industrial:
      - Number and size of structures (sq.ft.)
      - Type of construction and materials
      - Terms of sale (if applicable)
      - Details/terms of signed leases (rates, duration, etc.)
      - Projected terms for space not currently under lease
      - Details of any market studies completed or underway
   i. For ownership housing:
      - Type, number and size of units (sq. ft. & number of bedrooms)
      - Type of construction and materials
      - Anticipated sales price
      - Details of any market studies completed or underway
   j. For rental housing:
      - Type and size of building (# of floors, units, etc.)
      - Type of construction and materials
      - Size of units (sq. ft.) and number of bedrooms
      - Description of building/unit amenities
      - List of utilities included in rent
      - Monthly rental rates by unit type
      - Details of any market studies completed or underway

2. Development Budget (Sources and Uses) – During Construction Period

   Attach (and label as **Exhibit E**) a complete development budget for construction of the project. This budget should include a detailed listing of all sources and uses of funds.

   For each "use" of funds, indicate the methodology or means by which this estimated cost was derived (i.e. appraisal, contractor estimate, 4% of hard costs, actual cost, etc.)

   For each "source" of funds (debt, equity, public assistance, etc.), indicate the status of the funding source (committed, pending, projected, etc.), and the actual or anticipated financing terms/details.

3. Development Budget (Sources and Uses) – Permanent Financing

   If ownership of the project is being retained by the applicant (or affiliate or subsidiary) and permanent financing will be obtained, attach (and label as **Exhibit E-1**) a complete development budget upon permanent financing.

4. Operating Cash Flow Proforma (10 year)

   If ownership of the project is being retained by the applicant (or affiliate or subsidiary), attach (and label as **Exhibit E-2**) a projected 10-year operating cash flow proforma for the project. The proforma should clearly identify all assumptions, and should provide a detailed listing of all anticipated revenues, expenses, capital contributions/distributions, etc. The cash flow should clearly identify "Net Operating Income (NOI), "Cash Flow Before Taxes (CFBT)" and "Cash Flow After Taxes (CFAT)."

5. Payment of Application Fee ($ TBD. See letter.)

6. Signed authorization allows DMCC to check background of personnel involved in project.

Applicant Signature

The undersigned certifies that the above information is true and correct to the best knowledge of the undersigned:
The undersigned acknowledges and agrees that the $ TBD application fee associated with this request for public infrastructure funding is nonrefundable.

Signature:  Date: April 15, 2016

Name and Title: Regulatory and Legislative Affairs Manager

FOR DMMC USE ONLY

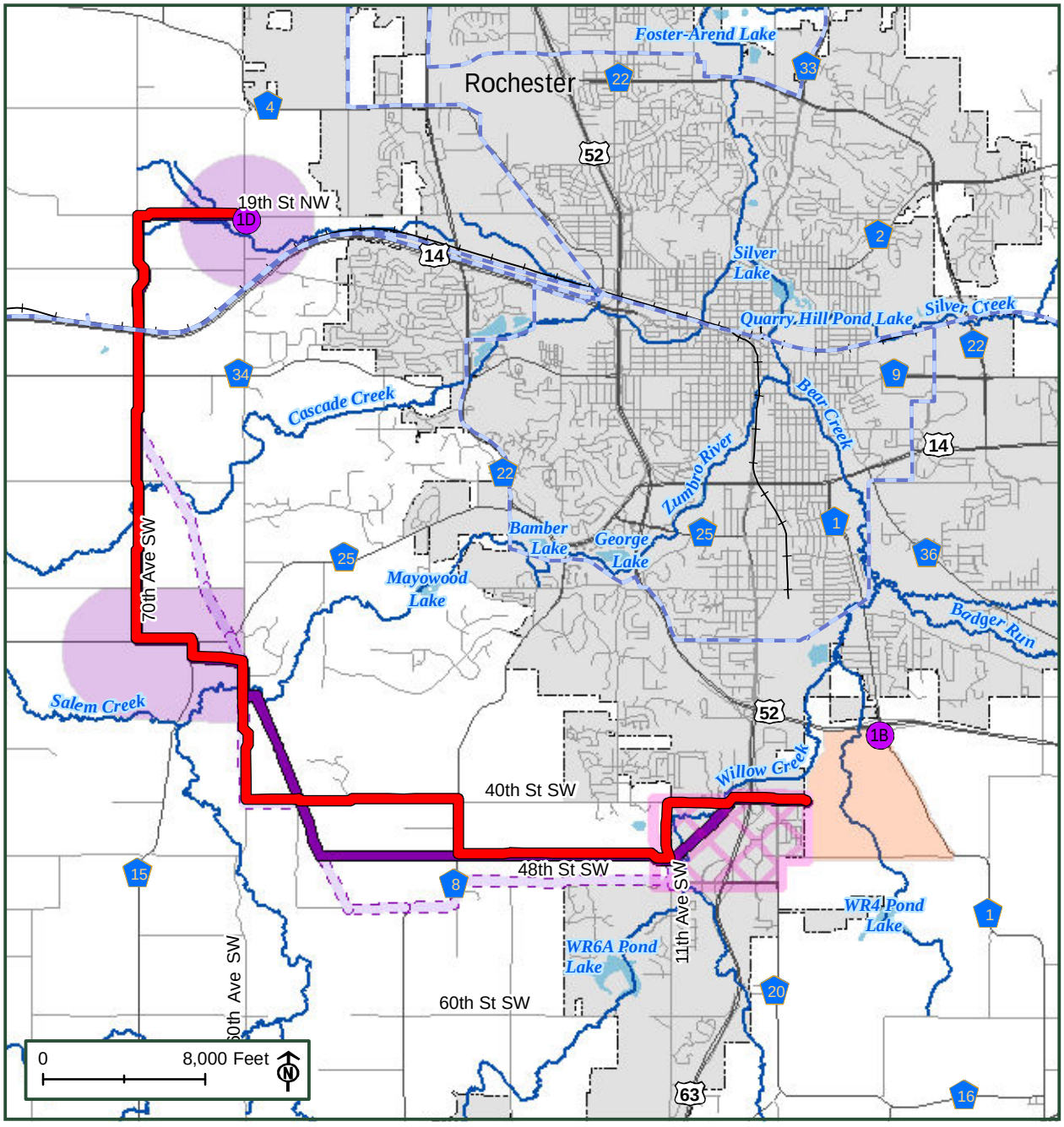
Complete application received: _____/_____/_____Staff Initials: _____

Non-Refundable Application Fee Paid: _____/_____/_____Check #: _____

Project Location

MINNESOTA ENERGY RESOURCES

Modified Preferred Route Overview



Legend

- Modified Preferred Route
- Preferred Route (Application)
- Alternate Route
- Town Border Station (TBS)
- Route Alternative Buffer
- Proposed Town Border Station & Route Buffer
- Proposed District Regulator Station & Route Buffer
- PWI Stream
- Waterbody/NWI Wetland
- City / Township Boundary
- Railroad
- 161kV AC Transmission Line
- Road
- US / State / County Highway

*Buffer distance is 1.25 miles

Path: \\mspe-gis-file\GISProj\050_den\232026_MERC\map_docs\Scoping_Comments\Attachment_Overview_8x11_P.mxd

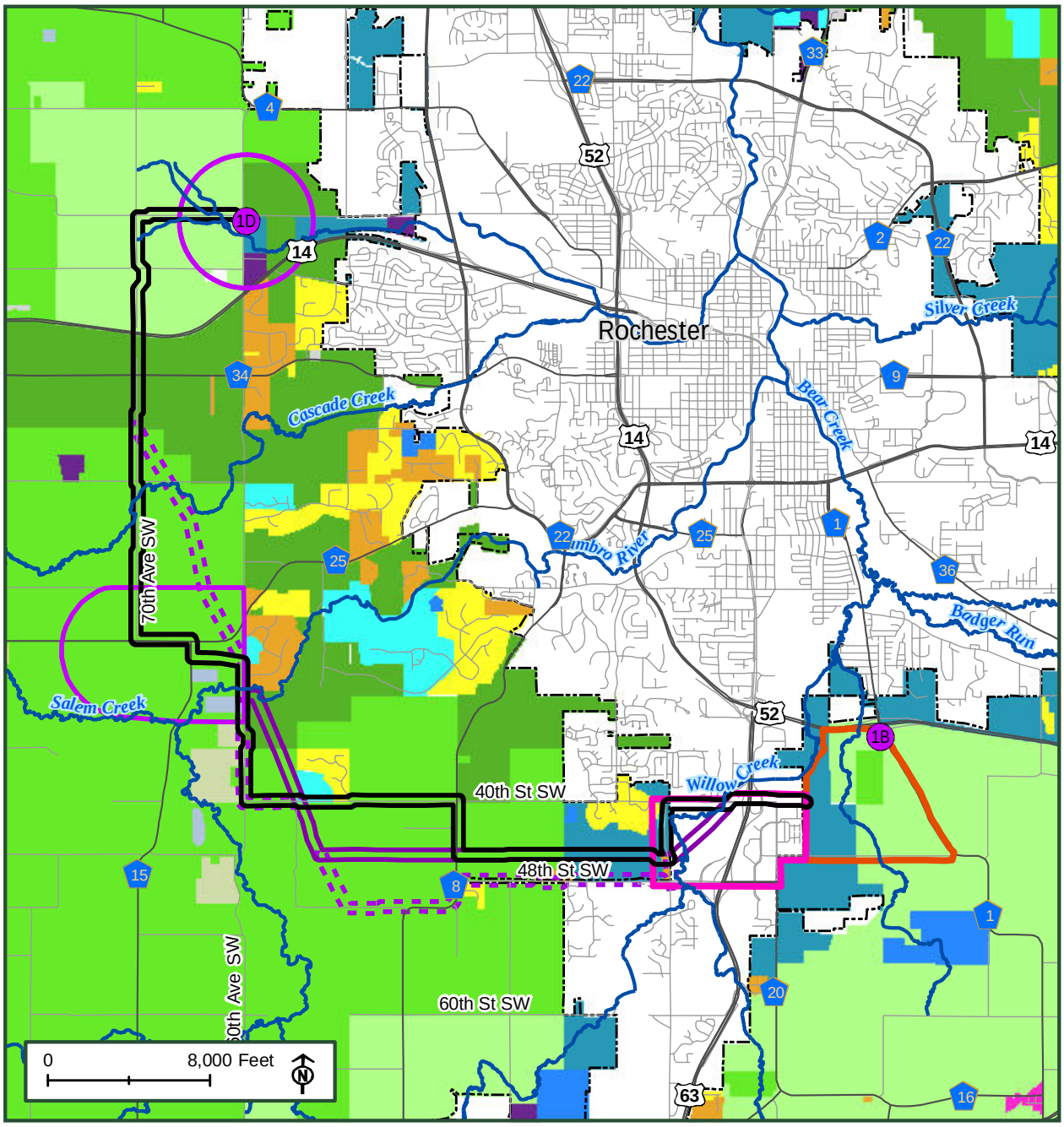
Ownership and Legal Structure

Minnesota Energy Resources Corporation ("MERC") is a Minnesota corporation that acts as the natural gas public utility in Rochester and in many of the surrounding communities. MERC will own, construct, and operate the proposed natural gas pipeline. MERC is subsidiary of WEC Energy Group, Inc. ("WEC"), a utility holding company headquartered in Milwaukee, Wisconsin. WEC's operating public utility subsidiaries provide electric and natural gas service to approximately 4.4 million customers over four states, including MERC's approximately 230,000 customers in Minnesota.

Zoning and Planning Maps

MINNESOTA ENERGY RESOURCES

Olmsted County Zoning



Legend

- Town Border Station (TBS)
- Modified Preferred Route
- Preferred Route (Application)
- Route Alternative
- Route Alternative Buffer
- Proposed Town Border Station & Route Buffer
- Proposed District Regulator Station & Route Buffer
- PWI Stream
- City of Rochester

Olmsted County Zoning

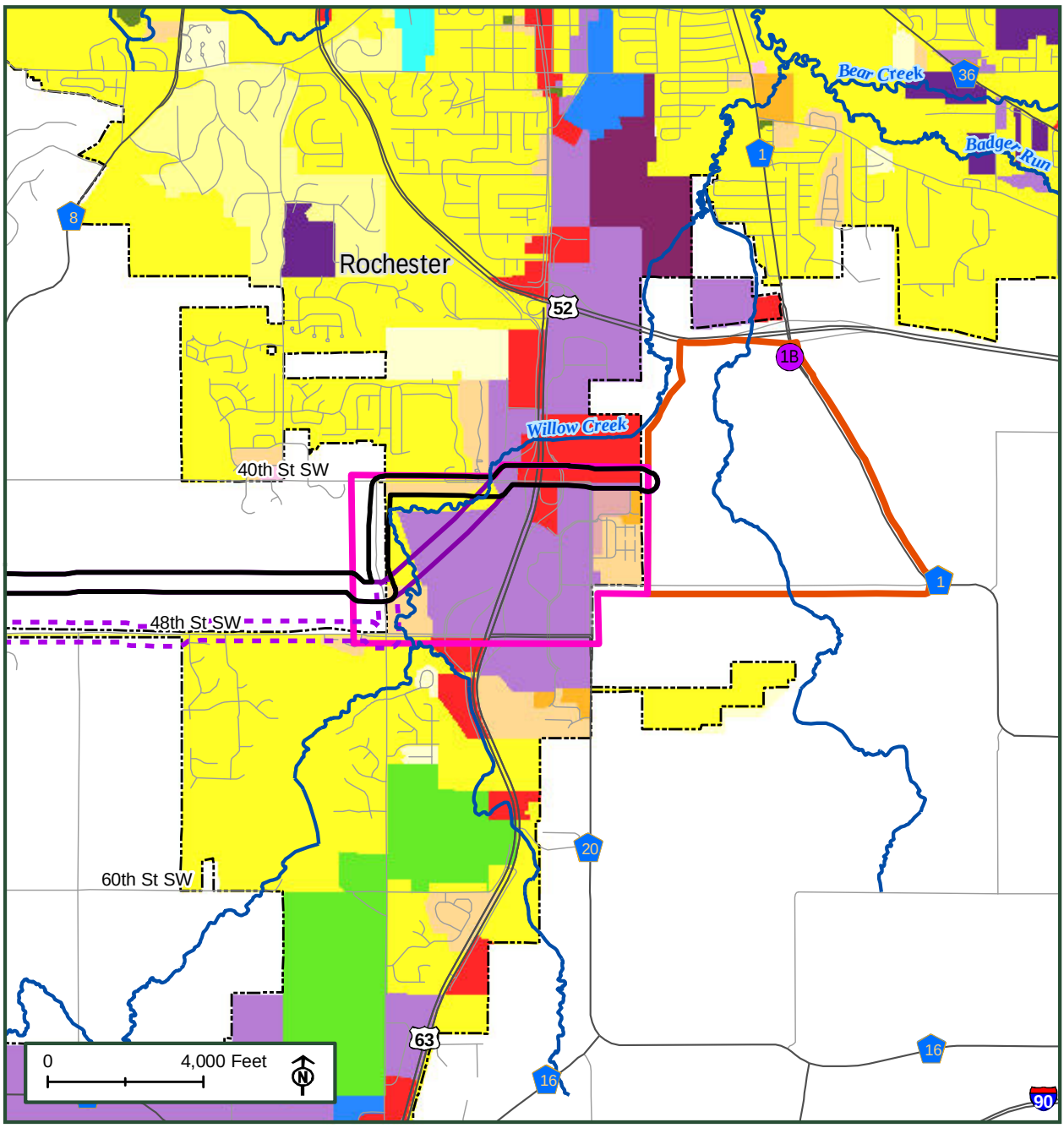
A/RC AER	A3	HC	R2	RSD
A1	A4	I	RA	SD
A2	AgRM	R1	RC	

*Buffer distance is 1.25 miles

Path: \\mspe-gis-file\GISProj\050_den\232026_MERC\map_docs\Scoping_Comments\Figure_08A_OlmstedZoning_8x11_P_with_MPRS.mxd

MINNESOTA ENERGY RESOURCES

Rochester Zoning



Legend

- Town Border Station (TBS)
- Modified Preferred Route
- Preferred Route (Application)
- Route Alternative
- Route Alternative Buffer
- Proposed District Regulator Station & Route Buffer
- PWI Stream
- City of Rochester

Rochester Zoning

AG	B5	M1	R-Sa	R2
B1	H	M2	R1	R3
B4	I	PUD	R1X	SD

*Buffer distance is 1.25 miles

Path: \\mspe-gis-file\GISProj\050_den\232026_MERC\map_docs\Scoping_Comments\Figure_08B_RochesterZoning_8x11_P_with_MPRS.mxd

Brief Description of the Proposed Project

1. **General Location:** See Exhibit A.

2. **Planned use and purpose:** The Project will expand the capacity of MERC's distribution system in and around the City of Rochester, which currently is at capacity. The Project will enable MERC to meet the projected increase in demand from its existing Rochester area customers, as well as from new customers who will be added to MERC's system as the result of the efforts to develop the Mayo Clinic as a Destination Medical Center. The Project consists of a high pressure (500 psig) distribution line linking TBS 1D, Proposed TBS, and Proposed DRS. See Figure 3 for location of the proposed phases.

3. **Planned in-service date:** The rebuild of TBS 1D is expected to be completed by the end of 2017, and the 16-inch diameter pipeline from TBS 1D to Proposed TBS is expected to be completed by the end of 2019. The 12-inch pipeline from Proposed TBS to Proposed DRS is expected to be completed by the end of 2022.

4. **General design and operational specifications for the type of pipeline for which an application is submitted:** The Project will include installation of approximately 26,900 feet (5.1 miles) of 16—inch-wide main (0.375 inch wall thickness (wt), X-60[1]) and approximately 42,250 feet (8.0 miles) of 12—inch-wide steel distribution pipe (0.375 inch wt, X-52) for a total of approximately 13.1 miles of pipeline.

[1] "X-60" refers to the grade of the pipe having a specified minimum yield strength of 60,000 psi.

Project Costs

The Rochester project is broken down into two phases. Phase I ($5.6 million of system improvements to MERC's delivery system in the Rochester area) has already been installed and recovery of those costs is included in MERC's current rate case, Docket G-011/GR-15-736. Phase II is the subject of this proceeding and is an approximately $44 million investment.

Phase I

Phase I has been completed. It involved modernizing, standardizing, and interconnecting portions of MERC's district regulator stations ("DRS") and piping within the city of Rochester. This will enable MERC to more efficiently and effectively balance the flow of natural gas on this low-pressure distribution system. Phase I was completed in late 2015 at a cost of $5.6 million.

Phase II

Phase II involves upgrading the TBS system serving the city. This includes (i) rebuilding one of MERC's two existing TBSs in Rochester; (ii) adding a new TBS and high pressure DRS to the system; and (iii) connecting the rebuilt TBS, New TBS, and New DRS with high pressure pipe to tie together the northern and southern portions of the existing TBS system. A breakdown of the costs for Phase II follow:

Table 2 – Rochester Gas Extension Project Construction Activities and Costs

Year	Cost	Activities
2014	$ 127,000	Initial Environmental Review and Consultant Contract
2015	$ 237,000	Regulatory Review (Rider Petition and Route Permit)
2016	$ 636,000	Engineering & design for TBS 1D and 5 miles of pipe to New TBS, route surveys
2017	$ 6,019,383	Surveys, easement acquisition, construction of TBS 1D, engineering & design
2018	$ 11,252,457	Survey, engineering & design, construction of pipe from TBS 1D to New TBS
2019	$ 5,475,520	Survey, engineering & design, construction of New TBS
2020	$ 6,950,442	Survey, engineering & design, construction of first segment of pipe from New TBS to New DRS
2021	$ 6,423,642	Survey, engineering & design, construction of second segment of pipe from New TBS to New DRS

Rochester Natural Gas Pipeline Project DMC Application ***Exhibit E***
Page 2 of 2

Year	Cost	Activities
2022	$ 6,833,562	Survey, engineering & design, construction of last segment of pipe from New TBS to New DRS
2023	$ 51,600	Project close-out
Total	**$ 44,006,607**	

From: Cody Pogalz <codypogalz@dmceda.org>
Sent: Friday, May 6, 2016 2:19 PM
To: Herring, Valerie
Cc: Mitchell Abeln; Krikava, Michael
Subject: RE: DMCC Funding Application by Minnesota Energy Resources Corporation

Val,

Yes, we will meet at our office at 195 South Broadway. The building exterior is marked as the "Rosa Parks Pavilion."

Please bring handouts for the group and feel free to call me if you have any questions.

Thanks,

Cody Pogalz
Executive Assistant
Destination Medical Center Economic Development Agency
195 South Broadway I Suite 12 I Rochester, MN
codypogalz@dmceda.org I 507.216.9720 I www.dmc.mn

From: Herring, Valerie [mailto:VHerring@Briggs.com]
Sent: Friday, May 06, 2016 2:10 PM
To: Cody Pogalz <codypogalz@dmceda.org>
Cc: Mitchell Abeln <mitchellabeln@dmceda.org>; Krikava, Michael <MKrikava@Briggs.com>
Subject: RE: DMCC Funding Application by Minnesota Energy Resources Corporation

Cody-

Yes, we are available to meet on Wednesday, May 18th starting at 3 p.m. Will the meeting be held at your office (195 South Broadway, Suite 12)? Also, does the meeting room have the ability to accommodate a PowerPoint presentation? If not, we can bring handouts just let me know.

We look forward to meeting with you.

Thanks,

Val Herring

Valerie T. Herring
Attorney

BRIGGS AND MORGAN

Briggs and Morgan, P.A.
Direct 612.977.8501

Fax 612.977.8650
vherring@briggs.com
2200 IDS Center | 80 South 8th Street | Minneapolis, MN 55402 | briggs.com

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From: Cody Pogalz [mailto:codypogalz@dmceda.org]
Sent: Thursday, May 5, 2016 11:40 AM
To: Herring, Valerie; Krikava, Michael
Cc: Mitchell Abeln
Subject: FW: DMCC Funding Application by Minnesota Energy Resources Corporation

Val and Michael,

Our team, consisting of Executive Director Lisa Clarke, Economic Development Director Patrick Seeb, and Finance Director Mitchell Abeln, along with City Assistant Administrator Gary Neumann, is available on Wednesday, May 18 from 3:00-4:00 p.m.

Are you available to meet with us in Rochester at that time?

Thanks,

Cody Pogalz
Executive Assistant
Destination Medical Center Economic Development Agency
195 South Broadway I Suite 12 I Rochester, MN
codypogalz@dmceda.org I 507.216.9720 I www.dmc.mn

From: Mitchell Abeln
Sent: Tuesday, May 03, 2016 5:24 PM
To: Herring, Valerie <VHerring@Briggs.com>
Cc: Krikava, Michael <MKrikava@Briggs.com>; Lisa Clarke <lisaclarke@dmceda.org>; Cody Pogalz <codypogalz@dmceda.org>
Subject: RE: DMCC Funding Application by Minnesota Energy Resources Corporation

Val & Michael,

The DMC EDA along with the City of Rochester would like to invite you and your team in to discuss and learn more about your proposed project. As part of our development process the DCM EDA and City of Rochester work side by side with the developer/project lead.

Cody, can you please work with Val to find time for this meeting.

Regards,

Mitchell Abeln, CFA, MBA
Finance Director
Destination Medical Center – Economic Development Agency
Email: mitchellabeln@dmceda.org
Work: 507.216.9725
Cell: 831.254.4491

From: Herring, Valerie [mailto:VHerring@Briggs.com]
Sent: Wednesday, April 27, 2016 2:53 PM
To: Mitchell Abeln <mitchellabeln@dmceda.org>

Cc: Krikava, Michael <MKrikava@Briggs.com>; Lisa Clarke <lisaclarke@dmceda.org>
Subject: RE: DMCC Funding Application by Minnesota Energy Resources Corporation

Mitchell-

Thank you for the update. We look forward to hearing from you.

Valerie T. Herring
Attorney

BRIGGS AND MORGAN

Briggs and Morgan, P.A.
Direct 612.977.8501
Fax 612.977.8650
vherring@briggs.com
2200 IDS Center | 80 South 8th Street | Minneapolis, MN 55402 | briggs.com

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From: Mitchell Abeln [mailto:mitchellabeln@dmceda.org]
Sent: Wednesday, April 27, 2016 2:48 PM
To: Herring, Valerie
Cc: Krikava, Michael; Lisa Clarke
Subject: RE: DMCC Funding Application by Minnesota Energy Resources Corporation

Valerie,

Thanks for reaching out and checking in. We at the DMC EDA are currently discussing this request with our City of Rochester partners and will be reaching back out to your group soon with questions/comments.

Cheers,

Mitchell Abeln, CFA, MBA
Finance Director
Destination Medical Center – Economic Development Agency
Email: mitchellabeln@dmceda.org
Work: 507.216.9725
Cell: 831.254.4491

From: Herring, Valerie [mailto:VHerring@Briggs.com]
Sent: Wednesday, April 27, 2016 2:26 PM
To: Mitchell Abeln <mitchellabeln@dmceda.org>
Cc: Krikava, Michael <MKrikava@Briggs.com>
Subject: RE: DMCC Funding Application by Minnesota Energy Resources Corporation

Mitchell-

Minnesota Energy Resources Corporation submitted an application for funding from the DMCC and the City of Rochester for their Rochester Natural Gas Extension Project on April 15th. I am writing to check-in on the status of that application and where the application sits in the application review process.

I would appreciate any insight that you can provide.

Thank you,

Val Herring

Valerie T. Herring
Attorney

BRIGGS AND MORGAN

Briggs and Morgan, P.A.
Direct 612.977.8501
Fax 612.977.8650
vherring@briggs.com
2200 IDS Center | 80 South 8th Street | Minneapolis, MN 55402 | briggs.com

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Rochester Natural Gas Pipeline Project

Presentation to Destination Medical Center Corporation
and the City of Rochester

May 18, 2016

Agenda

- Introductions
- Overview
- Need for Project
- Request for Funding
- Next Steps
- Questions/Discussion

About Minnesota Energy Resources

- Business
  - Natural gas distribution operations
  - Regulated public utility
  - 87 years of operation
  - 226 employees
- Market
  - Approximately 230,000 customers in 177 communities
  - Sole retail provider to Rochester and surrounding communities

Project Overview

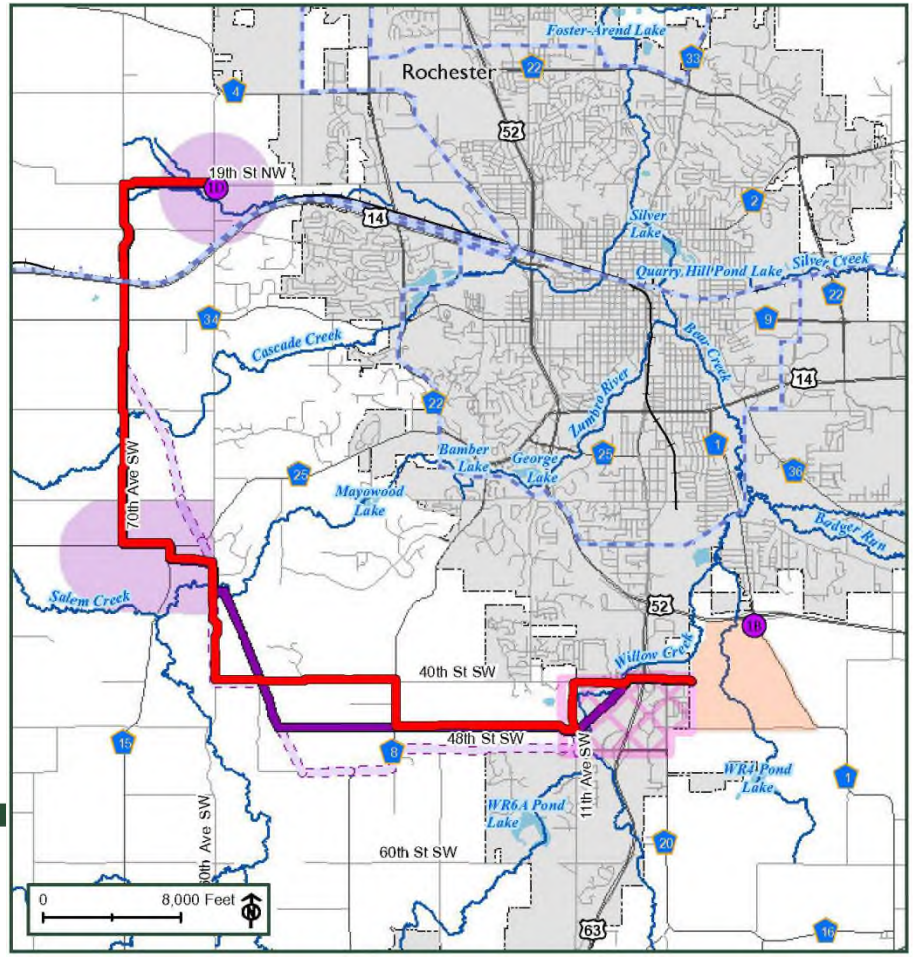
- Upgrade existing Rochester distribution system
  - Phase I completed in 2015 for $5.6 million
- Expand system to meet existing needs and growth
  - Phase II estimated at $44 million – construction 2017-22
- Add wholesale capacity – Northern Natural Gas
  - Significant capacity increase – long-term solution
  - Capital costs estimated at $55-60 million

Project Overview

- Phase II located west and south of Rochester – supports entire City and DMC Districts
- 13-mile pipeline ties City together
  - Increases capacity and improves interface
  - Standardizes pressures
  - Improves ability to move natural gas to growth areas

Proposed Project Route

- Solid purple line – preferred route in application
- Dashed line – route segment alternatives in application
- Solid red line – modified preferred route in scoping comments
- 5.1 miles of 16-inch pipe
- 8.0 miles of 12-inch pipe



Legend

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- US / State / County Highway

*Buffer distance is 1.25 miles

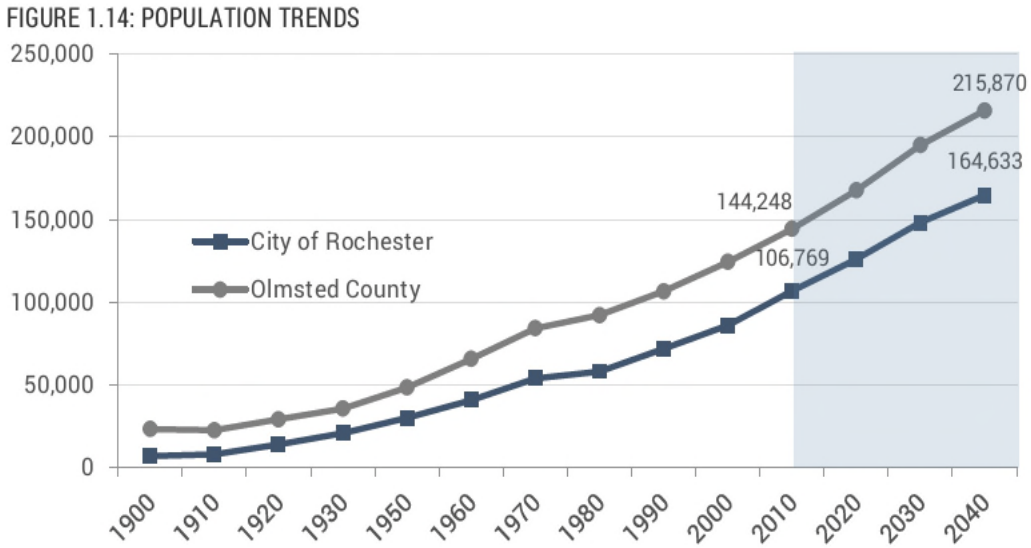
MINNESOTA ENERGY RESOURCES

Need for the Project

- Existing firm capacity completely subscribed
- Additional capacity needed to serve growth
- Increasing incidences of curtailing interruptible customers such as St. Mary's
- Polar vortex in January 2014 stretched system to the limit

Rochester Growth to Date

- Current Growth
  - City of Rochester-27% growth in population 2000-2012



Source: U.S. Decennial Census and Rochester-Olmsted Planning Department projections

Population Growth Increases Demand

- Customer count projected to grow from 44,062 in 2015 to 53,469 in 2025 (20 percent increase)

- Corresponding 20 percent demand increase means 103.6 million therms in 2015 to 123.7 million in 2025

DMC will be major driver of future growth

- Projected to create 35-45,000 jobs over next 20 years
- 2,200 to 3,100 new housing units in DMC Districts
- Retail demand in DMC Districts from 2015 to 2039 is 206,000-348,000 square feet
- Seven new hotels projected in DMC Districts 2014-34

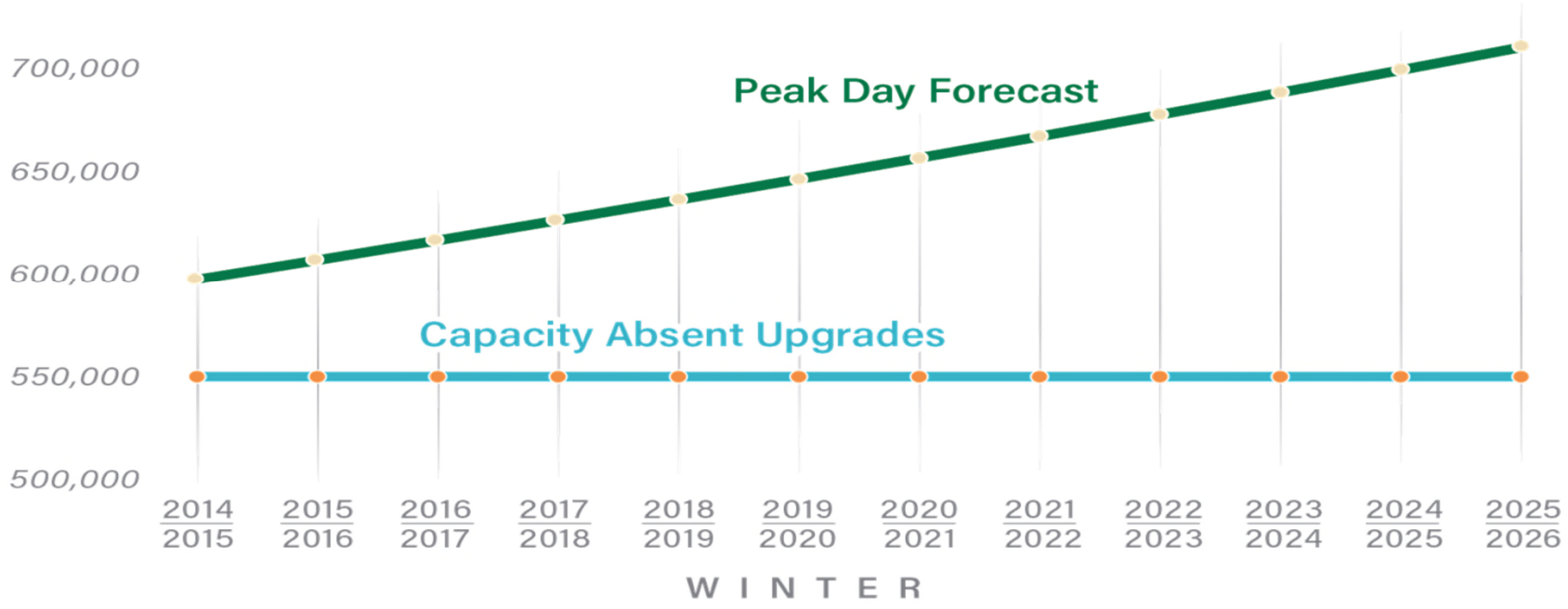
Brentwood Development

- Recently proposed $100 million housing and commercial development on Second Street SW
- 13 story building; underground parking; 359 housing units, and 20,000 square feet of commercial space

Other Developments in DMC Districts

- **Broadway At Center**
  - 24-story development of hotel, apartments, and retail
  - New load of 25.2 mcfh (approx. 272 dkth/day)
- **501 on First**
  - Luxury apartments and retail
  - New load of 20.4 mcfh (approx. 240 dkth/day)
- **Civic Center Addition**
  - Existing load of 17.9 mcfh
  - New load of 22.75 mcfh (approx. 300 dkth/day)
- **H3 building**
  - New restaurant
  - New load of 4.5 mcfh (approx. 57 dkth/day)

Current Capacity vs. Peak Demand



Project needed to achieve DMC goals and vision

- Project location outside Development Districts minimizes impacts within Districts
- Project indispensable to serve growth within Districts and spurred by overall DMC initiative

Project needed to achieve DMC goals and vision

- Success of DMC dependent on ensuring adequate natural gas service. Examples:
  - Current capacity inadequate to provide firm service to new development in and out of Districts
  - Banks require “letter to serve” as part of financing
  - Increasing impact to interruptible customers

Request for Funding

- Submitted application on April 15th
- Requested $5 million in funding from DMCC and City to offset costs

Next Steps and Questions

OAG No. 195

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:

David Kult

MPUC Docket No. G011/GP-15-895

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By: Ryan Barlow
Telephone: (651) 757-1473

Date of Request: May 10, 2016
Due Date: May 20, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Re: Staff Briefing Papers, April 21, 2016, Agenda Item 5, Docket Nos. G011/M-15-722, G-011/M-15-723 and G-011/M-15-724, p. 11. 3rd paragraph.

Was contract 127852 for firm or interruptible service?

Why was this contract not renewed?

RESPONSE:

Contract Number 127852 was for firm service.

As stated in Staff Briefing Papers, as part of its annual contract review, MERC revised contract 112486 from 66,271 Dth/day to 81,888 Dth/day. The capacity increase of 15,617 Dth/day was offset by MERC not renewing contract 127852 for 30,000 Dth/day. The result of MERC's contract restructuring was a 14,383 Dth/day capacity reduction.

MERC's approximate 14,000 Dth/day reduction in capacity corresponds to the reduction in MERC's design day requirements for 2015-2016. As reflected in staff briefing papers, MERC's NNG system saw a 6.03% decrease in design day requirements of 15,739 Dth/day, from 261,002 Dth/day in 2014-2015 to 245,263 Dth/day in 2015-2016. Accordingly, we reduced our capacity entitlements to maintain an appropriate reserve margin.

Response by Amber Lee
Title Manager of Regulatory and Legislative Affairs
Department Regulatory Affairs
Telephone (651) 322-8965

Although our design day requirements were reduced on MERC's NNG system overall in 2015-2016, we are short capacity on MERC's NNG system in the Rochester area. The overall reduction in design day does not alleviate the Rochester area constraints because without system upgrades MERC is not able to access or utilize additional capacity at the Rochester-area NNG interconnects.

Response by Amber Lee
Title Manager of Regulatory and Legislative Affairs
Department Regulatory Affairs
Telephone (651) 322-8965

OAG No. 117

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

Identify each instance in which MERC has curtailed any customer who would be served by the infrastructure upgrades for the Rochester Project in the last five years. For each instance, provide the following information:

1. Whether MERC curtailed all or some of the customers who could be curtailed;

2. The percentage of customers who could have been curtailed that were actually curtailed;

3. Whether there was any unauthorized gas use by customers who were called on to curtail during curtailment.

RESPONSE:

In accordance with MERC's tariffs, MERC makes every reasonable attempt to maintain continuous gas service to its customers. When operational or supply conditions require service interruptions, MERC follows the service priorities set forth in its tariffs. If the operational or supply condition is localized, MERC will only order curtailment by those customers within the specific geographic area(s) affected. If the operational or supply condition affects the entire state, MERC will require curtailment of all customers within each customer class, following the

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

order of priority set forth in MERC Tariff Sheet No. 8.41, until the operational or supply constraint is addressed.

When MERC curtails a class of customers as a result of a supply constraint, 100% of customers within the class are called to curtail. When MERC calls a curtailment as a result of operational conditions, MERC curtails 100% of those customers necessary to resolve the operational condition.

MERC did not curtail any customers in 2009, 2010, 2011, or 2012 who would be served by the infrastructure upgrades for the Rochester Project.

During 2013, MERC curtailed customers who would be served by the infrastructure upgrades for the Rochester Project as shown in the table below:

Date of Curtailment and Area Affected	# of Customers Curtailed	% of Customers Who Could Have Been Curtailed That Were Curtailed	Unauthorized Gas Use
January 21, 2013; Dodge Center, MN	1	100%	No
January 21, 2013; Byron, MN	3	100%	No
January 23, 2013; Byron, MN	3	100%	No
January 24, 2013; Byron, MN	3	100%	No
January 31, 2013; Dodge Center, MN	1	100%	No
January 31, 2013; Byron, MN	3	100%	No
February 1, 2013; Byron, MN	3	100%	No
February 19, 2013; Byron, MN	3	100%	No
February 19, 2013; Dodge Center, MN	1	100%	No
February 20, 2013; Byron, MN	3	100%	No
February 20, 2013; Dodge Center, MN	1	100%	No

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

MERC's 2014 curtailments of customers who would be served by the infrastructure upgrades for the Rochester Project are shown in the table below:

Date of Curtailment and Area Affected	# of Customers Curtailed	% of Customers Who Could Have Been Curtailed That Were Curtailed	Unauthorized Gas Use
January 6, 2014, Statewide	110 MERC only curtailed its LVI customers, which was sufficient to address the issue.	100%	Yes
January 23, 2014; Rochester, MN	1	100%	No
January 25, 2014; Statewide	All Large Volume Interruptible and Small Volume Interruptible customers	100%	Yes

MERC has not ordered any system operational or capacity curtailments in 2015. MERC did have one planned construction-related curtailment, however, on November 4, 2015, which affected four LVI customers.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

OAG No. 140

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

If MERC recovered the costs of the Rochester Project through base rates, how many years would recovery be spread over? In other words, if MERC recovers the costs of the Rochester Project through base rates, how long will it take the company to recover the costs of the Project?

RESPONSE:

Based on the assumed 50-year life of the Rochester Project, and the last portion of the Project going into rate base shortly after going into service in May 2023, the total cost of the Project would be fully depreciated and have no impact in rate base after 2073.

Response by: Seth DeMerritt
Title: Rate Case Consultant
Department: Regulatory Affairs
Telephone: (920)-433-2926

OAG No. 162

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from: David Kult

MPUC Docket No. G011/GP-15-895

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By: Ryan P. Barlow
Telephone: (651) 757-1473

Date of Request: April 26, 2016
Due Date: May 6, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Mead Direct Testimony, Tables 1, 2 and 3, pp. 21-25.

Provide a table similar to Table 2 with the inclusion of an excess Reserve Margin column for the rest of MERC customers receiving NNG capacity services.

Provide an explanation of the growth factors assumed to estimate the Design Day for Rochester customers and the rest of the MERC customers receiving NNG capacity services.

MERC Response:

See Attachment_OAG_162,which reflects the reserve margin for all of MERC's NNG-PGA except for the Rochester area. This table assumes the entire 20% that can be utilized outside of Rochester TBS 1D and 1B is utilized at other delivery points on the NNG-PGA. This table also assumes no design day growth year-over-year. Practically speaking, the 20% may be utilized at a combination of delivery points.

MERC's initial growth rate filed in the petition was 1.6%. This was revised to 1.5% in MERC's response to Department Information Request No. 15. The average growth rate to estimate the Design Day growth is based on the average growth rate of Rochester retail sales from the 10 year sales forecast that was prepared. Please see Excel files: DOC-15 Rochester Gas pipeline Certification Revised with Rochester Weather.xlsx Tab "Subp.3 B-Consumption and Cust" and DOC-15 Rochester Design Peak Day Analysis Revised with Rochester Weather.xlsx Tab

Response by: Sarah Mead and David Clabots
Title: Manager of Gas Supply and Senior Projects Specialist
Department: Gas Supply and Forecasting
Telephone: 920-433-7647 and 920-433-1355

"Regression Summary with AutoCor." MERC's response to Department Information Request No. 15 was served on the OAG in response to OAG Information Request No. 100 on March 29, 2016.

Response by: Sarah Mead and David Clabots
Title: Manager of Gas Supply and Senior Projects Specialist
Department: Gas Supply and Forecasting
Telephone: 920-433-7647 and 920-433-1355

OAG 162

Dth/Day

Winter Period	Total NNG Capacity	Total Rochester Capacity	Total NNG Minus Rochester	20% of Rochester Utilized elsewhere	NNG Capacity Plus 20% Less Rochester	NNG Design Day	Rochester Design Day	Total NNG Design Minus Rochester	NNG Reserve Plus 20% Minus Rochester	Reserve Margin				
2015/2016	252,127	55,169	196,958	0	196,958	245,263	60,929	184,334	12,623.50	7%				
2016/2017	252,127	55,169	196,958	0	196,958	245,263	61,842	183,421	13,537.43	7%				
2017/2018	252,127	55,169	196,958	0	196,958	245,263	62,770	182,493	14,465.07	8%				
2018/2019	268,066	65,669	202,397	-13,134	215,531	245,263	63,712	181,551	33,979.62	19%				Phase I
2019/2020	305,159	100,169	204,990	-20,034	225,024	245,263	64,667	180,596	44,428.29	25%				Phase II
2020/2021	305,159	100,169	204,990	-20,034	225,024	245,263	65,637	179,626	45,398.30	25%				
2021/2022	305,159	100,169	204,990	-20,034	225,024	245,263	66,622	178,641	46,382.86	26%				
2022/2023	305,159	100,169	204,990	-20,034	225,024	245,263	67,621	177,642	47,382.19	27%				
2023/2024	305,159	100,169	204,990	-20,034	225,024	245,263	68,636	176,627	48,396.51	27%				
2024/2025	305,159	100,169	204,990	-20,034	225,024	245,263	69,665	175,598	49,426.04	28%				
2025/2026	305,159	100,169	204,990	-20,034	225,024	245,263	70,710	174,553	50,471.02	29%				Re-allign 1B
2026/2027	305,159	100,169	204,990	-20,034	225,024	245,263	71,771	173,492	51,531.67	30%				
2027/2028	305,159	100,169	204,990	-20,034	225,024	245,263	72,847	172,416	52,608.23	31%				
2028/2029	305,159	100,169	204,990	-20,034	225,024	245,263	73,940	171,323	53,700.93	31%				
2029/2030	305,159	100,169	204,990	-20,034	225,024	245,263	75,049	170,214	54,810.03	32%				
2030/2031	305,159	100,169	204,990	-20,034	225,024	245,263	76,175	169,088	55,935.77	33%				
2031/2032	305,159	100,169	204,990	-20,034	225,024	245,263	77,317	167,946	57,078.39	34%				
2032/2033	305,159	100,169	204,990	-20,034	225,024	245,263	78,477	166,786	58,238.15	35%				
2033/2034	305,159	100,169	204,990	-20,034	225,024	245,263	79,654	165,609	59,415.31	36%				
2034/2035	305,159	100,169	204,990	-20,034	225,024	245,263	80,849	164,414	60,610.12	37%				
2035/2036	305,159	100,169	204,990	-20,034	225,024	245,263	82,062	163,201	61,822.86	38%				
2036/2037	305,159	100,169	204,990	-20,034	225,024	245,263	83,293	161,970	63,053.79	39%				
2037/2038	305,159	100,169	204,990	-20,034	225,024	245,263	84,542	160,721	64,303.18	40%				
2038/2039	305,159	100,169	204,990	-20,034	225,024	245,263	85,810	159,453	65,571.31	41%				
2039/2040	305,159	100,169	204,990	-20,034	225,024	245,263	87,097	158,166	66,858.47	42%				

OAG No. 147

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition, pages 15, 59.

MERC states that the maximum design capacity of the project is 151,000 mcfd. MERC also states that it will have a total contracted amount of "approximately 1 million therms per day." How are these figures related? Provide any formulas necessary to convert mcfd to therms per day.

RESPONSE:

"Mcfd" means a thousand cubic feet a day. One mcf of natural gas equals ten therms (1 dekatherm), so 151,000 mcf equals 1,510,000 therms. While the design capacity of Phase II's 13-mile high pressure piping being added to our system is equivalent to 1,510,000 therms (151,000 mcf), MERC is only contracting with NNG for capacity of approximately 1 million therms in light of our projected demand through 2025. We have designed the system to be able to accommodate future growth to avoid cumulative infrastructure upgrades.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

OAG No. 189

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:

David Kult

MPUC Docket No. G011/GP-15-895

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By: Joseph A. Dammel
Telephone: (651) 757-1061

Date of Request: May 6, 2016
Due Date: May 18, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Re: OAG IR 147; Mead Direct, at 21.

"While the design capacity of Phase II's 13-mile high pressure piping being added to our system is equivalent to 1,510,000 therms, MERC is only contracting for capacity of approximately 1 million therms in light of our projected demand through 2025." MERC states, however, that its Rochester Design Day in 2039/2040 is 870,970 therms.

Does this mean that MERC will be installing *system* capacity that has a reserve margin of roughly three times the current 2016 demand and, given MERC's demand projections, still roughly twice the demand in 2040?

MERC Response:

The design of the distribution system does not directly correlate to the contracted capacity volumes or the design day projections. The design capacity of MERC's distribution system needs to accommodate the peak hourly load which is generally greater than the contracted daily interstate capacity since there is not a consistent hourly load throughout the day

Response by Lindsay K. Lyle
Title Engineering Manager
Department Engineering
Telephone (651) 322-8909

OAG No. 176

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:

David Kult

MPUC Docket No. G011/GP-15-895

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By: Joseph A. Dammel
Telephone: (651) 757-1061

Date of Request: May 6, 2016
Due Date: May 18, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Describe any peaking facilities (propane-air, compressed natural gas, etc.) that MERC has on its system, specifically in the Rochester area. If there are none, explain whether MERC has investigated building a peaking facility to serve design day demand as an alternative to the Rochester Project. If MERC has not investigated this option, explain why.

MERC Response:

MERC no longer has any peaking facilities on its system. MERC retired or sold all of its peaking facilities due to age, reliability concerns, and their inability to provide additional firm capacity during peak demand times.

MERC notes that adding additional peaking facilities to the Rochester area would not be an effective solution to serve existing and forecast firm demand. Peaking facilities do not increase firm capacity on a system that has already reached its maximum capacity. As described throughout the Petition and in MERC's Direct Testimony, the distribution system in the Rochester area is already at capacity. Solutions such as adding propane-air, compressed natural gas will not increase capacity of the already-constrained system.

Response by: Amber S. Lee
Title: Regulatory and Leg. Affairs Mgr.
Department: Regulatory Affairs
Telephone: 651-322-8965

STAFF REPORT ON THE

BALTIMORE GAS AND ELECTRIC COMPANY'S

LNG AND PROPANE FACILITIES

MARYLAND PUBLIC SERVICE COMMISSION

Aurora D. Watson, Regulatory Economist
Rates Research and Economics

October 2, 2000

TABLE OF CONTENTS

I. Introduction

In accordance with the Commission Order No. 76260, issued June 19, 2000, in Case No. 8829, directing the Staff to fully investigate the historic and recent use of Baltimore Gas and Electric's (BGE) liquefied natural gas (LNG) and propane peak-shaving facilities by firm and interruptible customers, Staff herewith submits its report, conclusions and recommendations. Also, as directed by the Commission in Order No. 76260, Staff has investigated and includes herein information describing the economic dispatch of BGE's LNG and propane facilities and reports its conclusions and recommendations relative thereto.

II. Background

In Case No. 8829, BGE proposed to classify LNG and propane peak-shaving facilities as production and storage facilities and to assign their cost recovery solely to firm customers. BGE proposed to functionalize LNG and propane peak shaving facilities as production and storage related, and to allocate the costs on a class contribution to peak day. BGE's position was opposed by Building Owners and Managers Association of Metropolitan Baltimore, Inc. (BOMA).

Based on the record, the Hearing Examiner denied, in his proposed order, BGE's request to recover all LNG and propane costs from firm customers, and instead determined that both firm and interruptible customers should bear the cost of BGE's LNG and propane plant. Further, he determined that the interruptible class should bear costs proportionate to its use of those facilities. The Proposed Order of the Hearing Examiner, issued on April 21, 2000, was appealed by all parties.

In Order No. 76260, on the appeal of the Proposed Order, the Commission agreed that interruptible customers should not bear part of the cost of LNG and propane facilities. However, the Commission noted that the Hearing Examiner relied on BGE's admission that in fact interruptible customers have used the LNG and propane facilities on very cold days. The Commission directed Staff to (1) fully investigate the historic and recent use of the Company's LNG and propane facilities by firm and interruptible customers, (2) to investigate the economic dispatch of these facilities as discussed by the Company, and (3) to report its findings, along with appropriate recommendations, to the Commission on or before October 1, 2000.

III. The Purpose of BGE's LNG and Propane Facilities

BGE's LNG and Propane facilities were placed into service to (1) augment BGE's ability to meet distribution design day capacity needs of firm service customers; and (2) to allow BGE to provide an economic benefit to firm service customers by using these facilities to supply system load when the cost of natural gas is higher. [1]

[1] BGE response to Staff Compliance Data Request No. 1, Item No. 6

The LNG and propane facilities exist primarily to augment distribution facilities to meet design day capacity needs. They reduce the amount of "pipe" investment that would otherwise be needed to maintain system pressure during or near design day weather conditions. Originally constructed as a supply function, the subsequent design of the distribution system incorporated both LNG and propane into design day distribution capabilities. Under design day or near design day conditions, these facilities serve as geographically critical supply points on BGE's distribution system. The volume supplied by these facilities under these conditions could not be replaced with pipeline gas without a significant investment in BGE's distribution system infrastructure. [2]

Stated differently, because of their unique location on BGE's distribution system, the LNG and propane facilities are critical in maintaining system pressures when approaching design day conditions. Without these facilities, even if all of the physical gas supply to meet consumption could be obtained from the interstate pipelines at BGE's city gates, current distribution system piping is insufficient to deliver the gas to all customers while still maintaining adequate system pressures. To serve customers exclusively with interstate pipeline gas under design day-like conditions, BGE would have to reinforce its distribution piping in order to maintain the pressures needed to provide customers with reliable gas service.[3]

IV. Design Day Conditions

Design Day represents the way the distribution system must operate to reliably serve all firm customers on the peak day for which the system was designed. On BGE's system, design day conditions approach at and below 10° Fahrenheit (F). As design day conditions approach, the increase in gas consumed at the extremities of the distribution system causes the pressure to drop. Reliable gas pipe flow on a distribution system requires the gas to be maintained at a certain pressure. In order to maintain this pressure, BGE puts gas into the pipe from its LNG and propane facilities that are strategically located on the distribution system for this purpose.

When design day conditions exist, interruptible customers are not on-line. The distribution system was not sized to include interruptible deliveries on design day. As shall be discussed later in Section IX, a small amount of critical use gas is allowed interruptible customers. This small amount of critical use gas was assigned to the interruptible class in BGE's Cost of Service model which is used to allocate a portion of production and storage facilities to the interruptible class.

V. Economic Dispatch for Gas Supplied by BGE [4]

[2] BGE response to Staff Compliance Data Request No. 1, Item No. 11..
[3] Id.
[4] All information for Section V was from BGE response to Staff Compliance Data Request No. 1, Item No. 3.

Economic dispatch of supply resources matches the lowest cost supply option with sales customers' demand. The process is complex and inextricably linked with natural gas supply planning. Some natural gas purchase contracts have minimum purchase requirements that must be met. Storage inventories must be managed to maintain future deliverability. No-notice service (NTS)[5] and storage deliveries flexibility must be managed to meet hourly load changes and to avoid pipeline penalties. In addition, peak shaving inventories need to be managed to maintain peak day deliverability. The delivery and commodity resources available to BGE include:

Service	Max Dth/day City Gate
Columbia Firm Storage Service (FSS)	195,151
CNG General Storage Service (GSS)	39, 929
Columbia No-notice Service (NTS)	63, 000
Firm Transportation Service (FTS) on	
Columbia	112,218
CNG	60, 071
Transco	48, 764
BGE-owned peak shaving plants	
LNG	287,988
Propane	85, 000

Prior to the winter season, BGE establishes its summer/winter dispatch plan. This dispatch plan sets the monthly dispatch targets for each supply source, including storage injection and withdrawal targets. Three weather scenarios are addressed (normal, design, and mild). The storage plan must consider pipelines' various inventory requirements throughout the summer and winter. Additionally, Columbia FSS and CNG GSS have withdrawal and injection ratchets so that at certain inventory levels, the maximum daily withdrawal/injection is reduced. BGE also has winter season gas supply contracts to ensure reliability of firm contracts without binding BGE to purchase gas during the summer. Many of these contracts have minimum purchase commitments. Finally, the NTS contract and pipeline storage contracts provide the majority of the swing capability required by BGE's gas distribution system.

BGE's summer dispatch plan maximizes storage injections and capacity release/off system sales opportunities. The resources used to meet BGE's system demand and refill storage affect what capacity can be released. BGE actively releases temporarily unused pipeline capacity on a recallable or non-recallable basis.

Throughout the year, analyses are performed that reflect actual volumes dispatched and current storage inventories. Purchasing and storage activities are adjusted as required to ensure meeting all storage inventory requirements and minimum take

[5] No-notice Service is a firm interstate transportation service that offers BGE additional flexibility to store a limited volume of gas on the interstate pipeline.

levels in the purchase contracts, as well as to ensure the capacity is present to meet Design Day requirements.

Prior to each month, BGE establishes the initial schedule of flowing gas. The schedule takes into account the maximum and minimum sendout expected during the month. Pipeline nominations are due one business day prior to the first of the upcoming month. Once the month begins, BGE adjusts its monthly nominations and schedules gas based on Gas Control's five-day estimate. Daily scheduling establishes the amount of gas flowing to the city gate for the next gas day. If expected requirements are lower than flowing gas, BGE can either utilize its storage injection rights or sell gas through its off-system sales program based on economic conditions. If expected requirements are higher than flowing gas, BGE can either withdraw from storage (including NTS), recall any capacity released on a recallable basis, purchase city gate delivered gas if more economical than peak shaving, and finally peak shave with LNG and/or propane. The pipeline nominations establishing the mount of flowing gas typically have to be made no later than 12:30 PM on the day preceding the gas day.

The gas day begins with gas flowing based on the previous day's nominations. Using updated weather forecasts, BGE develops an initial estimate of the day's requirements. Throughout the gas day, the requirements estimate is continually updated based on actual weather and sendout.

If the updated gas requirement forecasts are different than the previous day's estimate on which the pipeline nominations were made, BGE dispatches supplies to match requirements. BGE dispatches additional flowing gas, storage gas, and/or peakshaving gas depending on economic conditions, while also taking storage and peak shaving inventories into consideration.

BGE nominates any additional flowing gas to the city gate. BGE states that it typically handles daily balancing with storage on CNG and Columbia. Injections or withdrawals are made to balance the system. These injections and withdrawals must be within the pipelines' tolerances or withdrawal penalties could be assessed by the pipeline. Balancing on Transco is handled with contingency scheduling and monthly cash-outs for monthly over or under tenders.

VI. Progression of Economic Dispatch [6]

As discussed above, BGE's dispatch of gas supply for its sales customers can be broken down into four main categories: baseload Firm Transportation, storage, additional flowing gas purchased mid-month, and LNG/propane. Below is the progression of gas dispatch on the three (3) coldest days for each of the last five (5) heating seasons. While this was primarily an economic progression, it may also reflect such considerations as storage/peakshaving inventories and flexibility in balancing supply at the city gate. These supplies are for BGE sales customers only unless otherwise noted. All units are in dth.

	Baseload Firm Transportation	**Storage**	**Mid Month Flowing Gas**	**LNG/ Propane**
1995/96				
2/3/96	295,000	179,000	0	100,000
2/4/96	290,000	170,000	0	164,000
2/5/96	286,000	193,000	0	136,000
1996/97				
1/17/97	254,000	186,000	13,000	138,000
1/18/97	254,000	186,000	35,000	151,000
1/19/97	254,000	185,000	37,000	73,000
1997/98				
12/31/97	214,000	229,000	0	1,000
3/11/98	155,000	215,000	69,000	24,000
3/12/98	155,000	200,000	86,000	4,000
1998/99				
12/25/98	202,000	175,000	0	0
12/31/98	199,000	227,000	0	2,000
1/5/99	136,000	234,000	63,000	82,000
1999/00				
1/17/00	160,000	208,000*	33,000	140,000
1/21/00	160,000	234,000*	18,000	101,000
1/27/00	160,000	238,000*	26,000	65,000

*includes Daily Requirements Service marketer owned gas from BGE controlled storage.

VII. Economic Use of LNG and Propane Facilities

[6] All information for Section VI. was from BGE response to Staff Compliance Data Request No. 1, Item No. 7.

Maintaining adequate system pressures is the driver for using LNG and propane facilities at or below 10° F. This would be necessary even if all physical gas supply could be obtained from interstate pipelines (i.e., through the citygate). Without the LNG and propane facilities BGE would have to reinforce its distribution piping, at significant expense to firm customers, in order to maintain the pressure needed to provide firm customers with reliable gas service when approaching design day conditions. [7] Therefore the LNG and propane facilities provide an economic benefit to firm customers when used to support the distribution system.

BGE functionalizes LNG and propane peak-shaving facilities as production and storage related and allocates costs on class contribution to peak day. (BGE Direct Testimony, Case No. 8829, Ex. 4 at 4.) This recognizes that these assets primarily exist to augment distribution facilities to meet design day capacity needs, since they reduce the amount of "pipe" investment that would otherwise be needed to maintain system pressure during or near design day weather conditions. This distribution function only begins when the temperature is at or below 10° F. When the temperature is above 10° F, the LNG and propane facilities are not used to support the distribution system or to maintain system pressure.

On days when there is sufficient distribution capacity, BGE bases its decision of whether to use LNG/propane or incremental interstate pipeline supplies based on both economic factors and LNG/propane inventory levels. Generally, at temperatures above 10° F, the use of LNG or propane occurs when it is a lower-cost substitute for interstate pipeline supplies to serve firm service sales customers. For example, if the cost of the incremental interstate pipeline supplies is less than the cost of LNG/propane, BGE would obtain these supplies to meet the requirements of its sales customers; if this cost is higher than LNG/propane, and there is sufficient inventory to meet design season requirements for the remainder of the winter, BGE would use these assets to meet the requirements of its sales customers. The savings are passed on to the sales customers. In either case, it is an economic decision on behalf of firm customers. [8]

VIII. Gas Supplied to Interruptible Customers

BGE discontinued commodity service to interruptible service customers in April, 1999. Prior to that time, interruptible customers had the opportunity to purchase gas on an interruptible basis in accordance with Tariff provisions for "Gas Commodity Price -- Interruptible". Under current Tariff provisions, gas may be provided month-to-month on a "best efforts" basis provided the Customer makes a nomination for such gas at least seven business days prior to the first day of the delivery month. This gas is priced at the "Gas Commodity Price-Firm" rate. The customer remains interruptible with 6 hours notice. In addition, the interruptible rate schedules provide for limited use of gas during

[7] BGE response to Staff Compliance Data Request No. 1, Item No. 11.
[8] BGE response to Staff Compliance Data Request No. 1, Item No. 12.

an interruption if permission is granted by the Company. [9] (See Schedule IS, p. 51 [10] and Schedule AIS, p. 62 [11].)

IX. Interruptible Customer Use of LNG and Propane Facilities

BGE allows very limited use of gas by interruptible customers during an interruption under certain conditions and upon request by the Customer. Interruptible customers are charged the Production Rate for this gas which includes both the gas commodity (for LNG and propane) plus LNG and propane operation and maintenance expenses. [12] In addition, interruptible customers are allocated a portion of production and storage costs in the COSS according to their critical use gas. [13] Critical use gas is billed to interruptible customers at the production rate.

BGE does not use LNG and propane facilities to serve Interruptible Service customers aside from critical use gas. IS/AIS customers are required by tariff to secure their own supply of natural gas and deliver that supply ("transportation gas") to BGE's City Gates for delivery to them through BGE's distribution system. IS/AIS customers do not, and by tariff are barred from, relying on BGE's peak shaving facilities as a source of supply. As a condition for receiving interruptible service, IS and AIS customers must install and maintain alternate fuel capability and must use it during periods of interruption.

Below is the BGE provided data from its "DSIS" database showing the amount of gas supplied to interruptible customers from BGE's LNG and/or propane facilities during the 3 day peak for years 1995, 1996, 1997, 1998, and 1999:

Year	3 Day Peak	LNG/Propane Supplied over 3 Days to Interruptible Customers
1995	2/4/95-2/6/95	0 dth
1996	2/3/96-2/5/96	2,283 dth
1997	1/17/97-1/19/97	18,387 dth
1998	3/10/98-3/12/98	0 dth
1999	1/4/99-1/6/99	0 dth

These volumes are based on gas used by interruptible customers at the Production Rate. These are the maximum volumes supplied from BGE's LNG and/or propane facilities. The Production Rate is charged any time BGE calls an interruption, the Customer obtains special permission for limited use of gas during the interruption, and the Customer uses in excess of its Transportation Gas. BGE may charge the Production Rate even on days when the LNG/propane facilities are not operating. [14]

[9] BGE response to Staff Compliance Data Request No. 1, Item No. 4.
[10] Schedule IS, page 51 is attached as Appendix A.
[11] Schedule AIS, page 62 is attached as Appendix B.
[12] BGE response to Staff Compliance Data Request No. 1, Item No. 2.
[13] Id.
[14] BGE response to Staff Compliance Data Request No. 1, Item No. 5.

X. Gas Imbalances and Failure to Interrupt

It is not the intent of this report to examine the just and reasonableness of existing gas imbalance and failure to interrupt provisions and penalties of interruptible customer tariffs. However, a brief description of the existing provisions and penalties is provided to demonstrate that interruptible customers pay a proportionate share of costs for imbalances as well as stiff penalties for failure to interrupt.

Interruptible customers must obtain gas commodity service from a third party gas supplier pursuant to the terms and conditions set forth in Schedules IS and AIS. Gas imbalances are subject to accumulated imbalance corrective measures when the customer's accumulated imbalance exceeds the applicable limit. The accumulated imbalance corrective measures price the imbalance gas at the Gas Commodity Price-Firm.

As discussed in Section IX, BGE may grant special permission for limited use of gas during an interruption under certain conditions and upon request by an interruptible customer. The interruptible customer is charged the Production Rate for this gas which includes both the gas commodity (for LNG and propane) plus LNG and propane operation and maintenance expenses. The Production Rate is increased by a penalty of $1.00 per therm for all gas used by the customer in excess of the permissible amount.

XI. Citygate Capacity

An entire section is devoted to this subject because of the attention it received in Case No. 8829. There is no evidence, above 10° F, that capacity is constrained at BGE's citygates. Nor is there any evidence that demonstrates that capacity at the citygates is "freed up" during peak winter days when BGE uses its LNG and propane facilities to maintain distribution system pressures.

City gate capacity is the maximum physical volume that can pass through the city gates. Operationally, this physical volume is limited by the "take-away" capacity of the distribution system. The "take away" capacity is dependent on the physical configuration of the distribution system, the total customer load, and the location on the distribution system of that load. For the last 10 years, only one day, 1/19/94, approached design day conditions. On this day the interruptible customer consumption was 14,000 dth which is essentially the amount of critical use gas assigned to the interruptible class in BGE's Cost of Service model. [15]

At temperatures above 10° F, capacity at the citygates is available throughout the year for interruptible throughput regardless of whether BGE's firm customers are supplied with gas from the LNG and propane facilities or from interstate pipelines through the citygate. As is discussed below, interruptible customers receive less gas

[15] BGE response to Staff Compliance Data Request No. 1, Item No. 15.

during peak winter days because of limits on interstate pipeline gas supply -- not citygate capacity.

XII. Interruptible Throughput

The throughput which BGE models to flow through BGE's citygates on design day is 731,000 dth/day. [16] At temperatures above design day conditions (2.7° F), citygate throughput can be higher. [17] Above 10° F, interruptible throughput is unaffected by the use of BGE's LNG or propane peak-shaving facilities. While interruptible customers are not on-line during design day conditions or when the temperature is at or below 10° F, there were "cold" days during winter months where there were both LNG and Propane facility use, and interruptible service throughput. [18] On these days, interruptible service customers used third party supplies, not BGE LNG or Propane. Since the temperature for these days was above 10° F, the LNG and propane facilities were not needed to support the distribution system.

From 1995 to 1999, where the specific days of interruption are known, the interruptions were either for interruptible "sales" customers (i.e., interruptions of BGE supplied gas) or for interstate pipeline interruptions of customer owned gas. In other words, all interruptions were supply related -- not distribution related. [19]

BGE interrupts distribution service when system pressure falls due to increased gas consumption by its firm customers. On days when the temperature is above 10° F, interruptible customers would have the same chance of being interrupted regardless of whether BGE used third party gas or LNG/propane to meet the requirements of its firm sales customers. (Third party gas meaning gas obtained on interstate pipelines.) Since interruptible customers supply their own gas, they are unaffected no matter how BGE supplies gas to its sales customers. [20]

XIII. Future Use of BGE's LNG and Propane Facilities

If in the future all firm customers were to receive gas from third party suppliers some reexamination of how rates reflect the use of LNG and propane facilities may become necessary. However, the current Daily Requirements Service (DRS) for firm distribution service customers taking commodity from third-party providers recognizes that the LNG and propane facilities serve a distribution purpose. While there may have been a presumption that interruptible customers benefit from "freed up" capacity when BGE's LNG and propane facilities are used to support the distribution system, there is no evidence at this time to indicate such a benefit would occur. As discussed above, when the LNG and propane facilities are used to support the distribution system, interruptible customers are not on-line. Therefore, the distribution purpose is only recognized for firm

[16] Id.
[17] BGE response to Staff Compliance Data Request No. 1, Item No. 13.
[18] BGE response to Staff Compliance Data Request No. 1, Item No. 15.
[19] BGE response to Staff Compliance Data Request No. 1, Item No. 19
[20] BGE response to Staff Compliance Data Request No. 1, Item No. 12.

customers – residential and non-residential. DRS determines the amount of gas that third party suppliers must deliver to their firm customers, and is applicable to residential Schedule D and non-residential Schedule C customers (this became effective for Schedule C customers in September 2000). [21]

Schedule DSG, which applies to Daily Requirements Service (DRS) Suppliers states that:

> On days when conditions approach design criteria when the Company engages in peak shaving activities to support distribution system pressures, the Supplier will receive a pro rata share of the peak shaving output. The peak shaving allocation is the difference between the Company's estimate of the Supplier's load and the Supplier's Daily Requirement. This peak shaving allocation is charged to the Supplier at the weighted average cost of peakshaving. (Schedule DSG, page 74.) [22]

The way this works is that DRS Suppliers are required to provide interstate pipeline supplies to their customers up to the maximum distribution capability to take gas away from the city gates. When peakshaving is required for distribution system purposes, these Suppliers are allocated a pro rata share of peak shaving commodity used to support distribution pressures for firm customers. The transaction occurs between BGE and an individual supplier. This methodology would continue to apply when all firm customers receive gas from third party suppliers. [23]

XIV. CONCLUSION

Staff has endeavored to answer the Commission's concerns by examining BGE's "adherence to gas facilities' design and use policies and practices and the economic considerations used in formulating interruptible customer rates."[24] In its Order, the Commission found "that interruptible customers should not bear part of the cost of LNG and propane facilities" and that BGE's "proposal to functionalize LNG and propane facilities as production and storage related and allocate by peak day is reasonable and equitable, and should be continued".[25] Staff has, therefore, interpreted the Commission's Order as an inquiry, not requiring any immediate action -- corrective or prospective. Staff also concludes from its investigation that no immediate action is warranted.

Staff is satisfied that BGE has demonstrated that, in its present merchant role, it has prudently and economically planned for the gas supply and distribution capacity required to serve firm customers through its gas facilities' design and use policies and

[21] BGE response to Staff Compliance Data Request No. 1, Item No. 18.
[22] Schedule DSG, page 74 is attached as Appendix C.
[23] BGE response to Staff Compliance Data Request No. 1, Item No. 18.
[24] Commission Order No. 76260 at p.27.
[25] Id.

practices. [26] BGE's economic dispatch methodology adheres to gas facilities' design and use policies and practices that benefit firm service customers. BGE has further demonstrated that the rates charged interruptible customers for a relatively small amount of critical use gas do, in fact, recover a reasonable portion of production and storage costs. [27]

The issue raised by BOMA in Case No. 8829 regards the capacity available for interruptible third party gas at the city gate as a result of BGE's decision to use its LNG and propane facilities to serve firm customers. Currently there is no evidence that, at temperatures above 10° F, capacity is either constrained at the citygates or "freed up" on the distribution system when the LNG and propane facilities are in use. In any event, the decision by BGE to use its LNG and propane facilities is primarily a consequence of its merchant function. However, if in the future the Commission were to require BGE to switch from a merchant role to exclusively delivery service, and all customers received third party gas, other questions would arise. The use of capacity at the city gate could at that time be one of many questions related to designing new distribution rates that equitably apportion the Company's costs to both firm and interruptible customers.

Therefore, Staff concludes that some departure from the allocation of the costs of BGE's propane and LNG plants to firm customers may be warranted at some point in the future when much more third party gas has replaced BGE system supply, or if the Commission requires BGE to leave the merchant function. At such time, this issue would be an appropriate one to include in the context of a much broader proceeding addressing the transition from BGE in its merchant function to one that is primarily delivery service. However, Staff concludes that no action is necessary at this time, nor would it be supportable from a ratemaking perspective based on the empirical evidence available to date.

[26] Under design day or near design day conditions, the volume supplied by the LNG and propane facilities could not be replaced with pipeline gas without a significant investment in BGE's distribution system infrastructure. (BGE response to Staff Compliance Data Request No. 1, Item No. 6.)

[27] Interruptible customers are charged the Production Rate for this gas which includes both the gas commodity (for LNG and propane) plus LNG and propane operation and maintenance expenses. In addition, interruptible customers are allocated a portion of production and storage costs in the COSS according to their critical use gas. (BGE response to Staff Compliance Data Request No. 1, Item No. 2.)

OAG No. 161

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from: David Kult

MPUC Docket No. G011/GP-15-895

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By: Ryan P. Barlow
Telephone: (651) 757-1473

Date of Request: April 26, 2016
Due Date: May 6, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Mead Direct Testimony, p. 14, line 1

Is a 15,000-hp compressor the minimum size necessary to enable the additional 45,000 Dth/day of additional capacity requested by MERC? If not, what is? What is the cost differential between this compressor and the 15,000-hp compressor?

What is the next size down? How much additional capacity would this size enable? What is the cost differential between this compressor and the 15,000-hp compressor? How much additional capacity is possible with this size compressor?

MERC Response:

Yes, a 15,000-hp compressor is the minimum size necessary to enable the additional 45,000 Dth/day additional capacity requested by MERC.

MERC is not in the interstate pipeline business and left the design of the interstate system to NNG. According to NNG, the proposed unit is the smallest size compressor unit that meets the design requirements. The Lake Mills unit must compress not only Minnesota Energy Resources Corporation's incremental growth entitlement of 53,032 Dth/day (45,000 Dth/day at Rochester plus 8,032 Dth/day for southeastern Minnesota) but also the 1,047,000 Dth/day of existing capacity flowing in the pipeline. Even without the southeastern Minnesota 8,032 Dth/day, the 15,000 horsepower compressor is needed, The flow rate requires a compressor site rating of at least 13,500 horsepower. Northern selected the smallest unit available from its vendor that met

Response by Sarah R. Mead
Title Manager of Gas Supply
Department Gas Supply
Telephone 920-433-7647

this design requirement with an expected site rating of 15,000 horsepower. In contrast, the next smallest unit available from the vendor has an expected site rating of 10,000 horsepower. Because the 10,000 horsepower compressor was not adequate to support the additional 45,000 Dth/day MERC requested, neither NNG nor MERC has analyzed the potential performance of the smaller compressor.

Response by Sarah R. Mead
Title Manager of Gas Supply
Department Gas Supply
Telephone 920-433-7647

OAG No. 148

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition, page 15.

How did NNG estimate that the costs for the upgrades will be approximately $55 - $60 million? Produce all documentation supporting the estimate. Produce any documents in Excel format with all links and formulas intact.

RESPONSE:

MERC does not have the details of how NNG estimates costs, however NNG was the lowest cost of the proposals. In addition, all capital construction risk will be borne by NNG as part of the fixed price proposal.

MERC does however have capital cost estimates from NNG for the following larger items:

15,000-hp compressor	$27,000,000
Rochester branch line MAOP Regulator	$646,000
Modify LaCrosse take-off setting	$376,000
Uprate LaCrosse branch line	$1,765,000

Response by: Sarah R. Mead
Title: Manager – Gas Supply
Department: Gas Supply
Telephone: (920) 433-7647

Rochester 1D unregulated delivery station	$755,000
12 miles/12-inch pipe to New Rochester TBS	$21,573,000
New Rochester TBS	$755,000

The total for these capital items is $52,870,000.

Response by: Sarah R. Mead
Title: Manager – Gas Supply
Department: Gas Supply
Telephone: (920) 433-7647

State of Minnesota
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

Nonpublic [ ]
Public [x]

Utility Information Request

Docket Number: G011/M-15-895 Date of Request: 4/29/2016

Requested From: Minnesota Energy Resources Corporation Response Due: 5/11/2016

Analyst Requesting Information: Adam Heinen

Type of Inquiry:

[ ] Financial	[ ] Rate of Return	[ ] Rate Design
[ ] Engineering	[ ] Forecasting	[ ] Conservation
[ ] Cost of Service	[ ] CIP	[ ] Other:

If you feel your responses are trade secret or privileged, please indicate this on your response.

Request No.	
33	Subject: Interruptible Cost Allocation Reference: Lee Direct, Page 29, Line 17 through Page 30, Line 2 MERC discusses the potential recovery of costs from interruptible customers. Please clarify whether the Company currently allocates demand costs to interruptible customers. If this information has already been provided in written comments or in response to an earlier DOC information request, please identify the specific comment cite(s) or DOC information request number(s). MERC Response: Distribution demand costs are allocated to all customer classes in MERC's Class Cost of Service, and are currently collected via the base distribution rates. The costs associated with the firm delivery of gas by the interstate pipelines to MERC's distribution system are not currently allocated to interruptible customers.

Response by: Amber Lee

Title: Regulatory and Leg. Affairs Mgr.

Department: Regulatory Affairs

Telephone: (651) 322-8965

List sources of information:

OAG No. 171

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:

David Kult

MPUC Docket No. G011/GP-15-895

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By: Ryan P. Barlow
Telephone: (651) 757-1473

Date of Request: April 27, 2016
Due Date: May 9, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Re: Lee Supplemental Direct 15-736, pp. 27-31, Exhibit ASL-3; Lee Direct 15-895, pp. 27-30

1. Provide the customer rate impact (Exhibit ASL-3) page 2, for all the customer classes including transport and interruptible customers for 2015-2025.

2. Are all customers classes contributing to the Phase II construction costs? If not, which customer classes are not, and why not?

3. Ms. Lee states in her testimony that transport and interruptible customers will benefit from the Rochester Project but also points out that only MERC's NNG system sales customers will cover all the costs of the NNG expansion through demand charges. She therefore suggests that it is fair, reasonable and appropriate to look to transportation and interruptible customers to cover a portion of the construction costs as well.

    a. Explain how a portion of the NNG construction costs could be allocated to the transport customers based on their benefits.
    b. Explain how the NNG construction costs could be allocated to interruptible customers through the commodity portion of the PGA.
    c. Assuming both the transport and interruptible customers contribute to the NNG construction costs based on the explanations 3a and 3b, provide a worksheet with all

Response by_____
Title_____
Department_____
Telephone_____

formulae and links intact for a tables similar to that on pages 1and 3 of Exhibit ASL-3 for all customer classes for 2017-2025.

MERC Response

1. Please see Attachment_OAG_171_Part 1.xlsx.
2. Yes, all customer classes are contributing to the Phase II costs. Under MERC's request for rider recovery all customers would pay a per therm rate for up to 33 percent of MERC's Phase II construction costs. In addition, in future rate cases the revenue requirement of Rochester Phase II will be allocated across all customer classes and all customers will contribute via distribution rates and customer charges.

3.

   a. Because transport customers contract for their own natural gas supply, MERC does not propose to allocate any portion of NNG construction costs to those customers.

   b. All or a portion of the NNG construction costs could be allocated to system sales interruptible customers by recovering the NNG costs through the commodity portion of the PGA rather than through demand charges. The Commission previously approved similar treatment of MERC's Bison/Northern Border Pipeline Contract in Docket Nos. G-011/M-11-1082, G-011/M-11-1083, G-011/M-11-1084, G-007/M-11-1088.

   c. See Attachment_OAG_171_Part 3.xlsx.

Response by Amber S. Lee
Title Regulatory and Legislative Affairs Manager
Department Regulatory
Telephone (651) 322-8965

Per Therm Rate Calculation -- NNG PGA

Calendar Year	Rochester Expansion Capacity Cost	NNG Residential Sales	NNG Small C&I Sales	NNG Large C&I Sales	NNG Interruptible	Albert Lea Residential Sales	Albert Lea Small C&I Sales	Albert Lea Large C&I Sales	Albert Lea Interruptible	Total NNG Pipeline General Service Sales	Per Therm Rate	Annual Average Residential Customer Impact (867 therms)
2017	$0	147,718,269	8,622,398	69,755,059	28,363,661	8,399,490	3,977,718	407,151	3,470,189	270,713,935	$ -	$ -
2018	$779,467	149,683,324	8,684,710	69,755,058	28,637,953	8,411,573	3,983,369	407,151	3,470,189	273,033,327	$ 0.00285	$ 2.48
2019	$5,420,031	151,757,672	8,749,679	69,755,058	28,789,787	8,423,886	3,989,159	407,151	3,470,189	275,342,581	$ 0.01968	$ 17.07
2020	$9,136,165	154,612,518	8,853,541	69,973,111	28,940,677	8,473,550	4,012,678	407,920	3,478,314	278,752,309	$ 0.03278	$ 28.42
2021	$9,136,165	156,211,257	8,885,417	69,755,058	29,164,175	8,448,284	4,000,786	407,151	3,470,189	280,342,317	$ 0.03259	$ 28.25
2022	$9,136,165	158,579,662	8,955,088	69,755,058	29,428,600	8,460,059	4,006,385	407,151	3,470,189	283,062,192	$ 0.03228	$ 27.98
2023	$9,136,165	161,035,739	9,025,215	69,755,058	29,671,835	8,471,747	4,011,948	407,151	3,470,189	285,848,882	$ 0.03196	$ 27.71
2024	$9,136,165	164,293,883	9,133,179	69,973,111	29,875,644	8,520,615	4,035,134	407,920	3,478,314	289,717,800	$ 0.03153	$ 27.34
2025	$9,136,165	166,192,298	9,164,587	69,755,058	30,026,533	8,494,504	4,022,794	407,151	3,470,189	291,533,114	$ 0.03134	$ 27.17

Per Therm Rate Calculation -- Rochester Only Sales

Calendar Year	Rochester Expansion Capacity Cost	Residential Sales	Small C&I Sales	Large C&I Sales	Interruptible	Total Rochester General Service Sales	Per Therm Rate	Annual Average Residential Customer Impact (867 therms)
2017	$0	37,859,050	1,836,610	18,902,860	2,042,230	60,640,750	$ -	$ -
2018	$779,467	38,499,170	1,867,810	19,052,320	2,077,390	61,496,690	$ 0.01267	$ 10.99
2019	$5,420,031	39,210,090	1,902,470	19,201,770	2,098,490	62,412,820	$ 0.08684	$ 75.29
2020	$9,136,165	39,986,080	1,939,190	19,351,230	2,111,160	63,387,660	$ 0.14413	$ 124.96
2021	$9,136,165	40,822,380	1,977,340	19,500,690	2,118,750	64,419,160	$ 0.14182	$ 122.96
2022	$9,136,165	41,714,850	2,016,650	19,650,150	2,123,310	65,504,960	$ 0.13947	$ 120.92
2023	$9,136,165	42,659,740	2,056,920	19,799,600	2,126,050	66,642,310	$ 0.13709	$ 118.86
2024	$9,136,165	43,653,650	2,098,030	19,949,060	2,127,690	67,828,430	$ 0.13470	$ 116.78
2025	$9,136,165	44,693,390	2,139,890	20,098,520	2,128,680	69,060,480	$ 0.13229	$ 114.70

OAG No. 173

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:

David Kult

MPUC Docket No. G011/GP-15-895

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By: Joseph A. Dammel
Telephone: (651) 757-1061

Date of Request: May 3, 2016
Due Date: May 13, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Re: OAG IR-152 Excel File attachment, "Attachment_OAG_152.xlsx."

Provide the same Excel files for both NNG and Consolidated for 2007–2025. Include worksheets for NNG and Consolidated with information on capacity costs for both Interruptible and Transport Customers.

For the Rochester data, use the sales data based on WN data for Rochester only, not the virtual weather station.

MERC Response

In discussions with the Office of the Attorney General it is MERC's understanding that the intention of this request is to allocate Northern Natural Capacity costs associated with this docket across all customers inclusive of Interruptible and Transportation customers. Please see Attachment_OAG_173.xlsx for this calculation.

Response by Amber S. Lee
Title Regulatory and Legislative Affairs Manager
Department Regulatory
Telephone (651) 322-8965

Per Therm Rate Calculation -- NNG PGA ALL Sales

Calendar Year	Rochester Expansion Capacity Cost	Current NNG PGA Sales	Albert Lea PGA Sales	Total NNG Pipeline (with Albert Lea) Sales	Per Therm Rate
2017	$0	610,686,733	18,189,299	628,876,032	$ -
2018	$779,467	612,988,388	18,207,033	631,195,421	$ -
2019	$5,420,031	615,279,543	18,225,136	633,504,679	$ 0.00856
2020	$9,136,165	618,791,410	18,309,103	637,100,513	$ 0.01434
2021	$9,136,165	620,243,253	18,261,161	638,504,414	$ 0.01431
2022	$9,136,165	622,945,751	18,278,535	641,224,286	$ 0.01425
2023	$9,136,165	625,715,191	18,295,786	644,010,977	$ 0.01419
2024	$9,136,165	629,687,378	18,378,624	648,066,002	$ 0.01410
2025	$9,136,165	631,365,823	18,329,389	649,695,212	$ 0.01406

Average Annual Bill Impact

		2017	2018	2019	2020	2021	2022	2023	2024	2025
Residential	867	$ -	$ 1.07	$ 7.42	$ 12.43	$ 12.41	$ 12.35	$ 12.30	$ 12.22	$ 12.19
GS Small C&I	1,015	$ -	$ 1.25	$ 8.68	$ 14.56	$ 14.52	$ 14.46	$ 14.40	$ 14.31	$ 14.27
GS Large C&I	8,633	$ -	$ 10.66	$ 73.86	$ 123.80	$ 123.53	$ 123.00	$ 122.47	$ 121.70	$ 121.40
Small Volume Interruptible Sales	53,503	$ -	$ 66.07	$ 457.75	$ 767.25	$ 765.56	$ 762.31	$ 759.01	$ 754.26	$ 752.37
Small Volume Joint Sales	54,241	$ -	$ 66.98	$ 464.07	$ 777.83	$ 776.12	$ 772.83	$ 769.48	$ 764.67	$ 762.75
Small Volume Interruptible Transport	130,459	$ -	$ 161.10	$ 1,116.16	$ 1,870.81	$ 1,866.70	$ 1,858.78	$ 1,850.74	$ 1,839.16	$ 1,834.54
Small Volume Joint Transport	94,486	$ -	$ 116.68	$ 808.39	$ 1,354.95	$ 1,351.97	$ 1,346.24	$ 1,340.41	$ 1,332.02	$ 1,328.68
Transportation for Resale	265,416	$ -	$ 327.76	$ 2,270.80	$ 3,806.13	$ 3,797.76	$ 3,781.65	$ 3,765.28	$ 3,741.72	$ 3,732.34
Large Volume Interruptible Sales	227,533	$ -	$ 280.98	$ 1,946.69	$ 3,262.87	$ 3,255.70	$ 3,241.89	$ 3,227.86	$ 3,207.67	$ 3,199.62
Large Volume Interruptible Transport	1,652,444	$ -	$ 2,040.61	$ 14,137.70	$ 23,696.42	$ 23,644.32	$ 23,544.03	$ 23,442.15	$ 23,295.47	$ 23,237.05
Large Volume Joint Transport	1,336,714	$ -	$ 1,650.72	$ 11,436.43	$ 19,168.78	$ 19,126.63	$ 19,045.50	$ 18,963.09	$ 18,844.44	$ 18,797.18
Super Large Volume Interruptible Transport	15,632,819	$ -	$ 19,305.06	$ 133,748.60	$ 224,178.15	$ 223,685.24	$ 222,736.44	$ 221,772.64	$ 220,384.98	$ 219,832.33
Super Large Volume Joint Transport	5,808,885	$ -	$ 7,173.43	$ 49,698.66	$ 83,300.72	$ 83,117.56	$ 82,765.01	$ 82,406.87	$ 81,891.25	$ 81,685.89

PUBLIC DOCUMENT—TRADE SECRET DATA HAS BEEN EXCISED

OAG No. 156

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	April 6, 2016
Telephone:	(651) 757-1473	**Due Date:**	April 18, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Provide the following information:

1. Provide all information or documents MERC possesses, and describe all communications MERC has had, regarding Rochester Public Utility's plan to build a new peaking plant at 5846 19th Street Northwest.

2. Provide a map of the plant, the TBS, and the proposed route of the new pipeline.

3. Will this peaking plant receive natural gas service from MERC? If so, describe the agreement.

    a. How much additional gas will be consumed by the plant?

4. If the plant will not receive natural gas service from MERC, where will it obtain its gas? Will this plant receive natural gas service directly from NNG?

5. When did MERC become aware of RPU's plan to build a new gas plant and how did it impact MERC's plans regarding the Rochester pipeline?

6. Why didn't MERC update OAG IR 108 when it became aware of RPU's plans?

Response by: Amber S. Lee and Lindsay K. Lyle
Title: Reg. and Leg. Aff. Mgr. / Engineering Mgr.
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965/ (651) 322-8909

PUBLIC DOCUMENT—TRADE SECRET DATA HAS BEEN EXCISED

7. Is MERC aware of any other gas generation units that RPU or any other entity plans to build that would receive service from the Rochester pipeline?

MERC Response:

1. As part of MERC's development and analysis of the Rochester Project, MERC met with RPU in November 2014 to discuss RPU's short- and long-term gas needs. At that time RPU did not indicate any definitive increase in demand and RPU did not indicate any plans to build a new natural gas peaking plant. The meeting agenda and presentation are attached to this response as Attachment_OAG_156_November 2014 Meeting.

   On February 24, 2016, the Rochester Post Bulletin reported that RPU had announced plans to construct a new peaking generation plant. According to the article, RPU plans to build the facility, to be called the Westside Energy Station, at 5846 19th Street NW in Rochester, with operations to begin by May 2018. MERC became aware of RPU's plans for the construction of the new peaking plant when those plans were made public at the end of February 2016. The Rochester Post Bulletin article is attached to this response as Attachment_OAG_156_RPB.

   On March 28, 2016, MERC met with RPU to discuss MERC's Rochester Project and RPU's future natural gas usage. At that time, RPU discussed the possibility of bypassing MERC's system and using a direct connect to Northern Natural Gas's (NNG's) system to supply the new Westside Energy facility. On April 8, 2016, MERC again met with RPU and NNG to discuss RPU's plans to obtain natural gas to serve its proposed peaking plant. During that meeting, on April 8, RPU indicated that they intended to have MERC provide natural gas for their new plant. **[TRADE SECRET DATA BEGINS…**

   …TRADE SECRET DATA ENDS]

2. A map of RPU's proposed peaking facility at 19th Street NW is attached as Attachment_OAG_156_Map. This map depicts the proposed peaking plant according to MERC's understanding of RPU's plans. MERC understands that RPU (or the City of Rochester) currently owns the parcel of land surrounding Rochester TBS 1D and that RPU plans to build the proposed peaking plant directly south of an existing building it owns near TBS 1D. As shown on the map, MERC currently has a 12-inch line, operating at 400 psig, which crosses directly north of the proposed peaking facility and connects to the east side of TBS 1D. NNG also has an existing lateral (the Rochester lateral) that feeds TBS 1D from the west. As shown on the map, MERC's preferred route for the proposed distribution line that is the subject of the route proceeding in Docket No. G-011/GP-15-858, also connects to TBS 1D from the northwest. As discussed more in part 4 of our response, as currently configured, RPU has the option to connect to either MERC's or NNG's system at the proposed location near TBS 1D.

Response by: Amber S. Lee and Lindsay K. Lyle
Title: Reg. and Leg. Aff. Mgr. / Engineering Mgr.
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965/ (651) 322-8909

PUBLIC DOCUMENT—TRADE SECRET DATA HAS BEEN EXCISED

3. As discussed above, RPU has considered two options to provide natural gas service to the planned peaking facility: service on MERC's system or service via a direct connection to NNG's system. During the meeting on April 8, 2016, attended by MERC, RPU, and NNG, RPU verbally indicated its intention to have MERC provide natural gas service to the proposed plant. At this time, no formal agreement has been executed.

    a. RPU indicated their anticipated natural gas usage would be **[TRADE SECRET DATA BEGINS …TRADE SECRET DATA ENDS].**

4. See response to (3) above.

5. As noted above, MERC became aware of RPU's plans to build a peaking plant at this location when RPU publicly announced its plans at the end of February 2016. As the parcel at 5846 19th Street NW and TBS 1D are currently situated, RPU could directly connect to MERC's system via MERC's existing 12-inch main. If RPU chose instead to bypass MERC and connect directly to NNG, RPU could connect to NNG's existing Rochester lateral, which is in direct proximity to the proposed facility. In other words, RPU has two options for service via the MERC and NNG system configurations and these options currently exist, independent from MERC's Rochester Project plans.

    Similarly, RPU's plans do not change MERC's Rochester Project plans. **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** RPU's plans to build a new natural gas peaking plant do not affect MERC's plans regarding the Rochester Project. Based on planning conversations with RPU, MERC is anticipating **[TRADE SECRET DATA BEGINS… ….TRADE SECRET DATA ENDS].** As shown on the table below, RPU currently uses **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** and MERC is unaware of any plans RPU might have to reduce this firm load. As of June 1, 2015, the Silver Lake Plant was converted to a natural gas steam producing facility that provides a contracted amount of steam to the Mayo Clinic campus for cogeneration needs. According to RPU's 2015 Update to its Infrastructure Study,[1] RPU intends to continue to provide approximately 50,000 pounds per hour of steam to Mayo through 2025 under the existing contract. The 2015 Update to RPU's Infrastructure Study is attached as Attachment_OAG_156_RPU Infrastructure Study.

    While interruptible and transport volumes do not factor into MERC's peak-day planning and therefore do not directly affect MERC's planning for its Rochester Project, **[TRADE SECRET DATA BEGINS…**

[1] RPU'S 2015 Update of the RPU Infrastructure Study is available at https://www.rpu.org/documents/2015_update_rpu_infrastructure_study.pdf

Response by: Amber S. Lee and Lindsay K. Lyle
Title: Reg. and Leg. Aff. Mgr. / Engineering Mgr.
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965/ (651) 322-8909

PUBLIC DOCUMENT—TRADE SECRET DATA HAS BEEN EXCISED

…TRADE SECRET DATA ENDS]. Cascade Creek Unit 1 is a 27 MW combustion turbine that uses both natural gas and fuel oil and RPU has indicated Unit 1 would be retired sometime between 2018 and 2026. **[TRADE SECRET DATA BEGINS…**

…TRADE SECRET DATA ENDS].

[TRADE SECRET DATA BEGINS….

RPU Facility	Customer Class	Average Annual Usage (Approximate)
Silver Lake Plant		
Cascade Creek Plant		
4 Office/Warehouse Meters		
New Westside Peaking Facility		

…TRADE SECRET DATA ENDS]

6. MERC did not update its response to OAG Information Request No. 108 because, at this time, MERC has not entered into any agreements to increase RPU's natural gas usage. As stated above, to the extent that RPU contracts with MERC to fuel its new plant, **[TRADE SECRET DATA BEGINS…**

   …TRADE SECRET DATA ENDS]. Nevertheless, MERC will update the response to OAG Information Request No. 108 as contractual developments occur.

7. No, MERC is not currently aware of any other gas generation units that RPU or any other entity plans to build that would receive service from the Rochester pipeline. RPU has discussed the possibility of using combined heat turbines to produce additional steam from the existing Silver Lake plant, but as far as MERC is aware, any plans of this nature have not been solidified.

The nonpublic version of this response contains nonpublic, trade secret customer contract and usage information information. This information meets the definition of trade secret information under Minn. Stat. 13.37, subd. 1(b). The information designated as nonpublic is not generally known to and not readily ascertainable by vendors and competitors of MERC, who could obtain economic value from its disclosure.

Response by: Amber S. Lee and Lindsay K. Lyle
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Ryan P. Barlow
Assistant Attorney General
Office of the Attorney General
Suite 1400
445 Minnesota Street
St. Paul, MN 55101-2131

June 3, 2016

RE: ***Voluntary Information Request in the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Natural Gas Extension Project.***
Docket No. G011/GP-15-895

Dear Mr. Barlow:

On behalf of the City of Rochester I am responding to your voluntary information request letter dated May 23rd sent to the City of Rochester. In your request you asked for information related to the most recent growth forecasts in the Rochester region out to at least 2030, and documentation to support the forecasts, in Excel format with links and formulas intact.

I have attached excerpts from our Consolidated Planning department's recent efforts to update the City's comprehensive plan. They show population and employment projections for both the City and Olmsted County. I also included information on economic growth and households to help build a more complete picture of the forecasted growth drivers for the region. This information was readily available in chart and graph form and does not contain the raw data in Excel format as you requested. If the raw data is critical to your work I will need to put you in touch with the staff at the Planning department to extract that from their complex planning models. Also, the following link can be used to access additional information related to forecasted growth.

http://www.rochestermn.gov/departments/planning-and-zoning/planning-2-succeed-rochester-s-comprehensive-plan-update

As you will note on page 4 of the information from the Rochester-Olmsted Planning Department, Olmsted County population grew by 78,716 from 1960 to 2010. The City of Rochester population grew by 52,406 from 1960 to 2010, doubling its population. The City has historically experienced a high growth rate, which is projected to continue. Employment growth in the City of Rochester has also contributed to the growth in many other cities and counties surrounding Rochester. A significant percentage of the jobs in Rochester are filled by

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workers commuting into the City. It is our understanding that the proposed MERC project serves a large area of Southeastern Minnesota.

Your second question asked how MERC's proposal to nearly double natural gas supply in the Olmsted County region supports the City's goal to use 100% renewable energy. I first want to clarify this goal. This was a proclamation made by our Mayor and does not represent a formal policy position adopted by the City Council. There has been no work done on evaluating the feasibility of such a goal and our current planning efforts are centered on meeting the State's renewable energy standard along with additional natural gas fired generation.

Below is a link to our Utility Board adopted infrastructure plan that outlines how RPU plans to meet its power supply obligations in the future.

https://www.rpu.org/about-rpu/infrastructure-planning/

I hope this provides the information you were looking for and please feel free to contact me if you need additional information or clarification.

Sincerely,

Mark Kotschevar
General Manager
Rochester Public Utilities
(507) 280-1601
mkotschevar@rpu.org

cc: Steven Kvenvold, City Administrator
Gary Neumann, Assistant City Administrator
Terry Adkins, Rochester City Attorney

OAG No. 139

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

Estimate total project revenues from the Rochester Project over the estimated life of the Project assets.

RESPONSE:

MERC does not have a forecast that projects sales for the 50-year life of the project (i.e., to 2073), and therefore we do not have projected revenues for the life of the Rochester Project.

Based on MERC's sales forecast included in this filing, the incremental revenues associated with the Rochester Project are forecasted to be $14,085,992 through 2025.

Response by: Seth DeMerritt
Title: Rate Case Consultant
Department: Regulatory Affairs
Telephone: (920)-433-2926

OAG No. 126

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

Identify with specificity any state laws, regulations, or rules that prevent the Rochester Project from being eligible for funding through Minn. Stat. §§ 469.40–.47.

RESPONSE:

Under the DMC statutory scheme, state infrastructure aid is available to the City of Rochester based on the level of expenditures that are made by the Mayo Clinic and other private entities for "Construction Projects" that are (i) undertaken pursuant to the Destination Medical Center ("DMC") Plan adopted by the DMC Corporation ("DMCC"), and (ii) physically located in the Medical Center Development District(s) that are part of the DMC Plan. Minn. Stat. §§ 469.43, subds. 1 and 5; 469.47, subds. 1(c)(2). Upon receiving the state infrastructure aid, Rochester must spend it on Public Infrastructure Projects ("PIPs"), which are broadly defined as projects identified in the DMC Plan that are "financed in whole or in part with public money." Minn. Stat. § 469.40, subd. 11(a); Minn. Stat. § 469.47, subd. 3(c). PIPs include the installation, construction, and reconstruction of "utilities systems and related facilities." Minn. Stat. § 469.40., subd. 11(a)(4).

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

Currently the Rochester Project is not part of the DMC Plan nor located within the plan's existing Medical Center Development District, and thus MERC's project costs are not currently eligible expenditures for purposes of determining the amount of state infrastructure aid to be provided to Rochester.

However, Rochester Project costs could become eligible expenditures that generate state infrastructure aid to the City if the DMC Corporation were to modify the DMC Plan and boundaries of the DMC Development District pursuant to Minn. Stat. § 469.43, subd. 4 to include portions of the Rochester Project within the city limits of Rochester. In addition, to obtain state infrastructure aid from the City, the DMC Plan would have to identify how the Rochester Project is being financed at least in part by public money. This public financing requirement would be presumably met if the City agreed to make a contribution in aid of construction of the Project.

MERC is not aware of any other state laws, regulations, or rules that prevent the Rochester Project from being eligible for funding under Minn. Stat. §§ 469.40–.47.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

OAG No. 127

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:		**MPUC Docket No.**	G011/GP-15-895

David Kult

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By:	Ryan P. Barlow	**Date of Request:**	November 4, 2015
Telephone:	(651) 757-1473	**Due Date:**	November 17, 2015

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Petition.

Identify with specificity any provisions of the Destination Medical Center Plan that prevent the Rochester Project for being eligible for the Plan.

RESPONSE:

As explained in MERC's response to OAG IR No. 126, the Destination Medical Center Corporation's ("DMCC") existing Destination Medical Center plan ("DMC Plan")[1] does not contemplate that MERC's Rochester Project would be eligible for funding because the Project is located outside the DMC development district as currently defined, and the Project is not a Public Infrastructure Project because it currently is not financed with any public money. MERC has been meeting with various stakeholders to determine if the DMC statutory scheme could be amended so that the DMC Plan could identify projects that support the DMC's infrastructure needs as eligible for funding regardless of where the project is located within the Rochester area. In the alternative, it may be possible under the current statutory scheme to amend the DMC Plan to allow funding to offset the portions of the Project located within the city limits. MERC will

[1] The draft DMC Development Plan is available at http://dmc.mn/press-materials/#devPlan.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

continue to work with the various stakeholders and other interested parties to determine what steps can be taken to obtain funding to cover some portion of the Project costs.

Response by: Amber S. Lee
Title: Regulatory and Legislative Affairs Manager
Department: Minnesota Energy Resources Corporation
Telephone: (651) 322-8965

OAG No. 170

State Of Minnesota
Office Of The Attorney General
Utility Information Request

Requested from:

David Kult

MPUC Docket No. G011/GP-15-895

In the Matter of the Petition of Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.

By: Ryan P. Barlow
Telephone: (651) 757-1473

Date of Request: April 26, 2016
Due Date: May 6, 2016

For all responses show amounts for Total Company and the Minnesota jurisdictional retail unless indicated otherwise. Total Company is meant to include costs incurred for both regulated and non-regulated operations.

Reference: Lee Direct Testimony, Exhibit ASL-3, p. 2.

Why was the application for funding from the DMCC limited to $5 million?

MERC Response:

In making its proposal for funding from the DMCC, MERC attempted to balance a number of factors, taking into account the structure of the DMC Plan and the potential limitations to funding a public utility project such as the MERC Rochester Project. Further, MERC was mindful that a reasonable funding request would likely have a greater chance of favorable treatment than a request for significant funding.

The $5 million request was a reasonable request under all of the circumstances. This figure approximates the amount of money MERC will spend within the city limits of Rochester to complete the project.. It also constitutes an approximate 10 percent discount on the overall MERC portion of the Rochester Project work in both Phase I and Phase II. It also constitutes about a 5 percent discount on the total $100 million project (including capacity payments to NNG). Each of those bases was reasonable in light of the circumstances.

Response by Amber S. Lee
Title Regulatory and Legislative Affairs Manager
Department Regulatory
Telephone (651) 322-8965

Notably, the DMC Plan focuses on specific designated "zones" and attempts to focus funding to projects within those zones. Very little of the work MERC (and NNG) are doing is physically located within the designated DMC zones. In fact, though MERC's Rochester Project will serve the retail, commercial and residential customers within the DMC development zones, the nature of MERC's project (natural gas pipeline and infrastructure) prohibits the construction of the project within the densely populated DMC districts. Nevertheless, the work benefits businesses and residents within the designated zones and constitutes infrastructure improvements that will aid the City as a whole in addition to the zones. Under those circumstances, MERC believes it was appropriate to request $5 million.

Response by Amber S. Lee
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