STATE OF MINNESOTA

July 1, 2016

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

RE: 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
MPUC Docket No. G011/M-15-895
OAH Docket No. 68-2500-33191

Dear Judge Cochran:

Enclosed please find the Direct Testimony and Attachments of Adam Heinen, Susan Peirce, and Michael Ryan, filed on behalf of the Minnesota Department of Commerce, Division of Energy Resources, in the above referenced matter.

The following sets forth the Public and Highly Sensitive Trade Secret (HSTS) versions by witness:

Witness	Public Volumes	Trade Secret Volumes
Adam Heinen	3 public volumes (Testimony & Attachments)	No trade secret volumes
Susan Peirce	1 public volume (Testimony & Attachments)	No trade secret volumes
Michael Ryan	1 public volumes (Testimony w/ Attachments)	1 HSTS trade secret volume (Attachments)

The foregoing was e-filed and e-served today on those on the attached service list.

The HSTS volume of Mr. Ryan's Attachments is e-filed in docket number G011/M-16-315.

Sincerely,

/s/ Linda S. Jensen
Assistant Attorney General
445 Minnesota Street, Suite 1800
St. Paul, MN 55101-2134
(651) 757-1472
Linda.S.Jensen@ag.state.mn.us

COUNSEL FOR THE MINNESOTA
DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

CERTIFICATE OF SERVICE

I, Sharon Ferguson, hereby certify that I have this day, served copies of the following document on the attached list of persons by electronic filing, certified mail, e-mail, or by depositing a true and correct copy thereof properly enveloped with postage paid in the United States Mail at St. Paul, Minnesota.

Minnesota Department of Commerce
Direct Testimony and Attachments of Adam Heinen, Susan Peirce and Michael Ryan

Docket No. G011/M-15-895 and G011/M-16-315

Dated this 1st day of July 2016

/s/Sharon Ferguson

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Mitchell	Abeln	mitchellabeln@dmceda.org	Destination Medical Center - Economic Development Agency	195 W Broadway Rochester, MN 55902	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Terry L.	Adkins	tadkins@rochestermn.gov	City Of Rochester	Room 247 201 4th Street SE Rochester, MN 55904	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Ryan	Barlow	Ryan.Barlow@ag.state.mn.us	Office of the Attorney General-RUD	445 Minnesota Street Bremer Tower, Suite 1400 St. Paul, Minnesota 55101	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Sundra	Bender	sundra.bender@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 Saint Paul, MN 55101-2147	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Elizabeth	Brama	ebrama@briggs.com	Briggs and Morgan	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Ardell	Brede	abrede@rochestermn.gov	Rochester City Hall	201 Fourth St SE Room 281 Rochester, MN 55904	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Bob	Brill	bob.brill@state.mn.us	Public Utilities Commission	121 E. 7th Place, Suite 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Jeanne	Cochran	Jeanne.Cochran@state.mn.us	Office of Administrative Hearings	P.O. Box 64620 St. Paul, MN 55164-0620	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Joseph	Dammel	joseph.dammel@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St. Paul, MN 55101-2131	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Laura	Demman	laura.demman@nngco.com	Northern Natural Gas Company	1111 S. 103rd Street Omaha, NE 68125	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Brett	Gorden	gorden.brett@mayo.edu	Mayo Clinic	200 First St SW Rochester, MN 55905	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Robert	Harding	robert.harding@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Mark	Kotschevar	mkotschevar@rpu.org	Rochester Public Utilities	4000 East River Road NE Rochester, MN 55906	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-895_Official CC Service List
David G.	Kult	dgkult@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th St. NW Rosemount, MN 55068	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Steven	Kvenvold	skvenvold@rochestermn.gov	City of Rochester - Administrator	201 4th Street SE Rochester, MN 55904	Electronic Service	No	OFF_SL_15-895_Official CC Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Amber	Lee	ASLee@minnesotaenergyresources.com	Minnesota Energy Resources Corporation	2665 145th St W Rosemount, MN 55068	Electronic Service	No	OFF_SL_15-895_Official CC Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Catherine	Phillips	catherine.phillips@we-energies.com	We Energies	231 West Michigan St Milwaukee, WI 53203	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Walter	Schlink	wschlink@rpu.org	Rochester Public Utilities	4000 East River Road NE Rochester, MN 559062813	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	Ste 122 9100 W Bloomington Frwy Bloomington, MN 55431	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Kristin	Stastny	kstastny@briggs.com	Briggs and Morgan, P.A.	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-895_Official CC Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-895_Official CC Service List

BEFORE THE MINNESOTA OFFICE OF 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

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

MPUC Docket No. G011/GR-15-895
OAH Docket No. 68-2500-33191

DIRECT TESTIMONY AND ATTACHMENT OF SUSAN L. PEIRCE

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

RATE DESIGN

JULY 1, 2016

DIRECT TESTIMONY OF SUSAN L. PEIRCE
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

MPUC Docket No. G011/GR-15-895
OAH Docket No. 68-2500-33191

TABLE OF CONTENTS

Section **Page**

I. QUALIFICATIONS....................1

II. PURPOSE OF TESTIMONY....................1

III. RATE DESIGN GOALS.................... 14

I. QUALIFICATIONS

Q. Please state your name, occupation, and business address.

A. My name is Susan L. Peirce. I am a Public Utility Rate Analyst with the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC). My business address is: 85 7th Place East, Suite 500, St. Paul, Minnesota 55101.

Q. What is your educational and professional background?

A. My educational and professional background is summarized in DOC Ex. ___ at SLP-1 (Peirce Direct).

II. PURPOSE OF TESTIMONY

Q. What are your responsibilities in this proceeding?

A. My responsibilities are to review the apportionment of revenue responsibility and rate design recommendations proposed by Minnesota Energy Resources Corporation (MERC) in its petition for evaluation and approval of rider recovery for its Rochester Natural Gas Extension Project.

Q. To which MERC witnesses do you respond?

A. I address the testimony of Ms. Amber Lee on rate design.

Q. Please summarize MERC's proposal.

A. MERC proposes to recover a portion of the Phase II costs of its Rochester Project through a Natural Gas Extension Project Rider (NGEP Rider) as permitted under Minn. Stat. §216B.1638. Phase II involves reconstruction of the town border stations that serve Rochester and construction of the transmission infrastructure necessary to move additional capacity into the Rochester area. Department witnesses Adam Heinen and Michael Ryan discuss the specifics of the project in more detail. In addition, MERC proposes to charge to its ratepayers the portion of the costs charged to MERC by Northern Natural Gas (NNG) for the additional interstate pipeline capacity to the area through the NNG Purchased Gas Adjustment (PGA).

Q. What direction do Minnesota Statutes provide regarding rate design?

A. Minn. Stat. §216B.1638 permits gas utilities to recover costs associated with a natural gas extension project outside of a general rate case through the implementation of a NGEP Rider. Specifically, the statute states:

> A public utility may petition the commission outside of a general rate case for a rider that shall include all of the utility's customers, including transport customers, to recover the revenue deficiency from a natural gas extension project.

Minn. Stat. § 216B.1638 also limits recovery under the rider to no more than 33 percent of the costs of the natural gas extension project. Minn. Stat. § 216B.1638, subd. 3 (c).

Q. What is MERC's NGEP Rider proposal?

A. MERC proposed to recover one-third of the revenue deficiency associated with the upgrade of its distribution system in the Rochester area through its NGEP Rider. MERC proposed to file its annual NGEP Rider by October 1 each year with rates that MERC proposes to be effective January 1st of the following year. Under MERC's proposal, the filing would include the projected rider-eligible revenue deficiency and the proposed per therm Rider rate. MERC proposed that the NGEP Rider rate would be calculated annually, and would include a true-up to reflect actual revenues and expenses. MERC Ex.____ at 17 (Lee Direct).

Q. How does MERC propose to apportion its Rochester Project revenue requirement among its customer classes?

A. MERC proposed to recover its Rider revenue deficiency on a flat per therm basis from all customers. Under MERC's proposal the Rider rate would be calculated by dividing the annual revenue deficiency by total therm sales to both sales and transport customers.

Q. Do you agree with this methodology?

A. Not entirely. While I do not object to a per therm basis for simplicity in the rider, I conclude that the issue is somewhat more complex than reflected in MERC's proposal. Instead, I recommend that MERC's Rider revenue deficiency first be split so that at least 50 percent of the costs recovered in the rider would be charged to ratepayers in Rochester, with the remaining amount of the costs charged to ratepayers outside of Rochester, before calculating a flat per therm charge for each group of customers

Q. Why do you recommend a 50/50 or other split in the revenue requirement between Rochester and non-Rochester customers?

A. The Rochester Project would most directly benefit Rochester area customers, by improving reliability and allowing for additional growth with the addition of the proposed Destination Medical Center. Consequently, I recommend that Rochester customers pay for half of the NGEP Rider costs of the project. At that same time, customers outside the Rochester area would also benefit from improved reliability on MERC's system, as discussed in the testimony of Department Witness Michael Ryan. I note that the 50/50 split of costs refers to the amount remaining after assignment of costs to Rochester Public Utilities, per the testimony of Department Witness Adam Heinen.

I recommend that the Commission consider apportioning at least 50 percent of the costs to Rochester customers and the remaining amount of the costs to non-Rochester customers. Rochester customers represent approximately 20 percent of MERC's total customer base, and 13.5 percent of MERC's total sales. MERC Ex.____ at 10 (Clabots Direct) and MERC Ex.____at ASL-1 (Lee Direct). Apportioning half the costs to Rochester would more accurately reflect cost-causation of the Project. In addition, because the Rochester Project will accommodate growth in sales in the Rochester area, the burden of the higher apportionment per Mcf will be reduced over time.

I request that MERC calculate the rates based on a 50/50 split and provide a bill impact analysis in Rebuttal.

Q. How does MERC propose to recover NNG's costs associated with the increase in interstate pipeline capacity?

A. MERC proposes to recover the costs of increasing the capacity on NNG's interstate pipeline through the NNG PGA, and charging the costs to all MERC customers served off NNG's pipeline.

Q. Do you have any concerns with MERC's proposal to recover capacity costs from all customers subject to the NNG PGA?

A. I defer to Adam Heinen's testimony on this issue.

III. SUMMARY OF DEPARTMENT RECOMMENDATIONS

Q. Please provide a summary of your recommendations.

A. I recommend that the Commission:

- Apportion at least 50 percent of the revenue deficiency to MERC's Rochester customers and the remaining amount to MERC's non-Rochester customers, calculated on a per therm basis for each group.
- Approve the recovery of NNG pipeline capacity costs through MERC's NNG PGA.

In addition, I request that MERC provide the rates by customer class under this recommendation and a bill impact analysis in its Rebuttal. Specifically, I request that MERC's analysis assume a 50/50 revenue split between Rochester and non-Rochester customers with separate per therm rates for the two groups.

Q. Does this complete your Direct Testimony?

A. Yes.

Susan L. Peirce
Minnesota Department of Commerce, Division of Energy Resources
85 Seventh Place East, Suite 500
St. Paul, Minnesota 55101

Professional Background

Public Utilities Rate Analyst in the Electric and Telecommunications Units, Minnesota Department of Commerce. 1991 – Present.

Testimony in Contested Case Proceedings:

- G011/GR-15-736, Minnesota Energy Resources Corporation General Rate Case
- G008/GR-15-424, CenterPoint Energy General Rate Case
- E002/GR-13-868, Xcel Energy General Rate Case
- G011,007/GR-13-617, Minnesota Energy Resources Corporation General Rate Case
- E002/GR-12-961, Xcel Energy General Rate Case
- E002/GR-10-971, Xcel Energy General Rate Case
- E001/GR-10-276, Interstate Power & Light General Rate Case
- E017/GR-10-239, Otter Tail Power Company General Rate Case
- E015/GR-09-1151, Minnesota Power General Rate Case
- E111/GR-09-175, Dakota Electric Association General Rate Case
- E002/GR-08-1065, Xcel Energy General Rate Case
- G011,007/GR-08-835, Minnesota Energy Resource Corp. General Rate Case
- E015/GR-08-415, Minnesota Power General Rate Case
- ET2,E002/CN-06-1115, CAPX2020 Certificate of Need
- E002/GR-05-1428, Xcel Energy General Rate Case
- E001/GR-05-74,. Interstate Power & Light Company General Rate Case
- P421/C-96-1540, US WEST Generic Cost Case
- P421/M-97-371, AT&T Wireless Services, Inc.'s Petition for arbitration with US WEST Communications, Inc.
- P421,466/M-96-1097, Sprint Communications Company L.P.'s Petition for arbitration with US WEST Communications, Inc.
- P421,442/M-96-855, P5321,421/M-096-909, P3167,421/M-96-729, Petition by MCI Metro, MFS Communications, and AT&T for arbitration with US WEST Communications, Inc.

Community Faculty Member, Metropolitan State University, 1990 - 1994.
Associate Economist, Norwest Corporation, 1988 - 1991.
International Credit Analyst, Norwest Bank Minneapolis, 1985 - 1988.

Education

M.A. in Economics, University of Nebraska - Lincoln.
B.S. in Economics, Nebraska Wesleyan University, Lincoln, Nebraska.

BEFORE THE MINNESOTA OFFICE OF 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

IN THE MATTER OF THE APPLICATION OF MINNESOTA ENERGY RESOURCES CORPORATION FOR AUTHORITY OF RIDER RECOVERY FOR THE ROCHESTER NATURAL GAS EXTENSION FOR NATURAL GAS SERVICE IN MINNESOTA	MPUC Docket No. G011/M-15-895 OAH Docket No. 68-2500-3319

PUBLIC TESTIMONY AND ATTACHMENTS OF MICHAEL RYAN

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE

DIVISION OF ENERGY RESOURCES

JULY 1, 2016

DIRECT TESTIMONY OF MICHAEL RYAN
IN THE MATTER OF THE APPLICATION OF MINNESOTA ENERGY RESOURCES CORPORATION FOR AUTHORITY OF RIDER RECOVERY FOR THE ROCHESTER NATURAL GAS EXTENSION FOR NATURAL GAS SERVICE IN MINNESOTA

MPUC Docket No. G011 M-15-895
OAH Docket No. 68-2500-33191

TABLE OF CONTENTS

Section .... **Page**

I. INTRODUCTION 1

II. PURPOSE AND SCOPE 2

III. RFP AND NEED FOR ADDITIONAL INFRASTRUCTURE 3

V. SUMMARY OF RECOMMENDATIONS 14

I. INTRODUCTION

Q. Would you state your name, occupation and business address?

A. My name is Michael Ryan. I am employed as a Public Utilities Rates Analyst by the Minnesota Department of Commerce, Division of Energy Resources (Department). My business address is 85 7th Place East, Suite 500, St. Paul, Minnesota 55101-2198.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Finance and a Bachelor of Arts degree in German from Saint Cloud State University in 2006.

I have seven and a half years' experience in the natural gas industry in the private sector with U.S. Energy Services, Inc. From 2009 to 2012, I worked as a Gas Operations Analyst and coordinated natural gas transportation on the major interstate pipelines in Minnesota including, but not limited to, Northern Natural Gas (NNG), Northern Border Pipeline (NBPL), Viking Gas Transmission (Viking), Alliance Pipeline (Alliance), and Great Lakes Gas Transmission (GLGT). From 2012 until January 2016, I held the position of Retail Energy Originator. I was responsible for delivered retail natural gas and electric supply contracts throughout North America including the establishment of timing for responses, inclusion of correct factors specific to each retail facility, and evaluation of pricing and proposals. Specific to natural gas, I issued in excess of 75 requests for proposals (RFPs) per year.

I joined the Department of Commerce as a Public Utilities Rates Analyst in February of 2016.

Q. What are your responsibilities in this proceeding?

A. My responsibility in this proceeding is to review the RFP conducted by Minnesota Energy Resources Corporation (MERC or the Company) to acquire the natural gas resources that are the subject of this proceeding. I reviewed testimony provided by MERC witnesses Mr. Timothy C. Sexton, and Ms. Sarah R. Mead regarding the RFP. The purpose of this review is to determine: a) whether MERC selected the least cost alternative to meet the proposed need, consistent with the requirement of Minn. Stat. § 216B.1638 subd.3 (b) (2), and b) whether MERC met the statutory requirement to show that "project costs are reasonable and prudently incurred" in order for MERC to recover in a rider the costs of a natural gas extension project.

Q. Do you address all issues associated with this Project in your testimony?

A. No, I do not. Department Witness Adam Heinen addressed the Company's forecasted need for the project, the Company's cost recovery proposal through the Natural Gas Extension Project rider, and the relationship of the project to the proposed Destination Medical Center. Department Witness Sue Peirce addressed the apportionment of revenue responsibility associated with the rider proposal.

II. PURPOSE AND SCOPE

Q. Please provide a description of proposed Rochester Extension Project.

A. On October 26, 2015, MERC filed a Petition for approval of rider recovery of costs for the extension project to serve Rochester, MN and the surrounding area (the Rochester Project or Project). The Company has stated that the Project is necessary because the distribution system is currently at capacity and upgrading is needed to meet current and future demand. As part of the upgrade, NNG will have to expand the capacity of its interstate pipeline to support the upgrade to MERC's distribution system. MERC Ex. __ at p. 1 (MERC Petition).

Q. Did the Company evaluate the pricing provided by NNG?

A. Yes, MERC conducted an RFP with multiple parties to determine if the best and most cost effective option was to remain with the incumbent provider of service to Rochester, which is NNG. The summary results of this RFP process were provided by MERC in its **Highly Sensitive Trade Secret** Response to DOC Information Request (IR) No. 38. **Highly Sensitive Trade Secret** DOC Ex. ____ at MR-1, Attachment_DOC_38_HIGHLY SENSITIVE TRADE SECRET.pdf (Ryan **Highly Sensitive Trade Secret** Direct).

III. RFP AND NEED FOR ADDITIONAL INFRASTRUCTURE

Q. Do you address whether there is a need for the project?

A. No, that issue is addressed in the Direct Testimony of Adam Heinen.

Q. Assuming that there is a need for new interstate pipeline capacity, did MERC demonstrate that there were no other viable options to meet this need?

A. Yes, MERC witnesses addressed that the other options available to meet need of ratepayers in the Rochester Area would be: to take no action, conservation, upgrade the distribution system, realign other NNG capacity, purchasing capacity from other pipelines, and use peaking facilities on days of increased demand on the distribution system. The Company responded to these various options as follows:

1. No action: The Company stated that it has a shortfall of delivery entitlement to the Rochester city gates and that with demand expected to grow, it will need additional capacity. There is also no incremental capacity that can be purchased from NNG or other shippers transporting natural gas to Rochester. MERC Ex. ____ at 8 (Mead Direct).
2. Conservation: MERC stated that while conservation of energy among customers in Rochester can reduce the demand growth rate somewhat, it has not been sufficient to eliminate the growth in demand. MERC Ex. ___ at 8 (Mead Direct). The Company further explained that demand side savings are not enough to meet the anticipated customer growth and the current shortfall. MERC Ex. ___ at 9 (Mead Direct).
3. Upgrading the MERC distribution system: Even with upgrades to the distribution system, there are limits based on the amount of natural gas that can be delivered to the Rochester Town Border Stations (TBS) from the upstream interstate pipeline. Upgrades to MERC's distribution system address only issues downstream from the two TBSs. MERC Ex. ___ at 9 (Mead Direct).

   To help demonstrate this point, I prepared a simple flow chart that is included as an attachment to this testimony. DOC Ex. ___at MR-2 (Ryan Direct). It illustrates the movement of gas from extraction through the point in which it is received by MERC's customers. As shown in the attachment, upgrading MERC's distribution system is downstream from the interstate pipeline and does not lessen the needs at the TBS. Thus the constrained interstate pipeline and flow into the TBS cannot be addressed solely by upgrading MERC's distribution system (although upgrades to MERC's distribution system may also be needed).

4. <u>Realignment of other MERC-owned NNG capacity</u>: According to MERC, there are only two TBSs where NNG delivers natural gas to the Rochester area: Rochester 1B and 1D MERC Ex. ___ at 7 (Sexton Direct). While the Company has 193,423 Dekatherms (Dth)/day of firm delivery entitlement on NNG to stations that are not Rochester 1B & 1D MERC Ex. ___ at 9 (Sexton Direct), the use of this capacity to deliver natural gas to Rochester would be unreasonable given that the capacity has alternative delivery paths. The Company does not carry excess capacity to the other points so, if the firm delivery entitlement were realigned to deliver natural gas to Rochester, capacity would then have to be added for multiple points to replace the capacity needed in those areas. MERC Ex. ___ at 9 and 10 (Sexton Direct). In other words, the other capacity is already needed at other delivery points.

   Moreover, even if it were possible to move gas supplies intended for other areas of MERC's system, this alternative would not address the need since it would still require NNG to expand physical delivery capability to Rochester.

5. <u>Purchase of capacity from other interstate pipelines</u>: No other pipelines currently serve Rochester, so this is not currently an option. While service from other pipelines is certainly not impossible, other pipelines would have to build infrastructure to reach Rochester. MERC Ex. ___ at 12 (Sexton Direct).

6. Use peaking facilities to address need for distribution capacity: The Office of the Attorney General ("OAG") requested information on peaking facilities in the Rochester area. In its Response to OAG IR No. 176, MERC stated that it no longer has any peaking facilities on its system. MERC also added that peaking facilities would not be a solution to serve Rochester, because the distribution system has already reached capacity. Similar to Option 3. above, this alternative would only address the issues behind MERC's distribution system and not the constraint on the interstate pipeline. DOC Ex. ___ at MR-3 (Ryan Direct).

Q. What criteria did you use when evaluating MERC's competitive process?

A. I evaluated the RFP process to assess whether it was inclusive of potential parties and if participating parties were held to a fair process. I also evaluated the process to determine if MERC selected the lowest cost option and ensured there were reasonable provisions to protect ratepayers.

Q. Did MERC use a competitive bidding process to address the additional pipeline capacity needs?

A. Yes. On January 5, 2015 MERC issued an RFP to NNG, NBPL, Viking, Great Lakes, and Encore. MERC Ex. ___ at 38 (Sexton Direct). The RFP was also posted to the MERC website to allow for additional solicitation.

Q. Do you believe there were other parties that could have been included in the RFP?

A. Yes. The Alliance Pipeline travels through southern Minnesota near the Rochester Area. I issued discovery seeking clarification as to why Alliance was not included in the RFP. In its Response to DOC IR No. 44, MERC stated that the additional cost of building a processing plant, given that Alliance is a wet pipeline, made use of this pipeline cost prohibitive and logically impractical. DOC Ex. ___ at MR-4 (Ryan Direct).

Q. What is a wet pipeline?

A. When the natural gas is extracted or gathered from the natural gas field, there are additional hydrocarbon liquids and impurities that come with the natural gas. A wet pipeline is able to transport the denser hydrocarbon mix and extract the additional hydrocarbons at the point of delivery instead of at the extraction point. My understanding of MERC's Response to DOC IR No. 44 is that a processing plant would have been needed at the interconnection between Alliance and MERC's distribution system to extract the hydrocarbon liquids and allow the "dry" natural gas to flow into Rochester. The Company's Response to IR No. 44 also stated that a consultant for Alliance did make an inquiry based on the RFP, but no bid was received.

Q. What do you conclude, based on MERC's response?

A. I continue to conclude that MERC should have included Alliance in the RFP and designed the RFP to request proposals for delivery of "dry" gas. Such an approach would have allowed for confirmation that use of the Alliance Pipeline was cost prohibitive. Nonetheless, since Alliance did not submit a bid, I conclude that this issue is reasonably addressed in this proceeding.

Q. Have you had an opportunity to review the RFP?

A. Yes. MERC provided the RFP in Response to OAG IR No. 132. DOC Ex. ____at MR-5, Attachment_OAG_132_RFP.pdf (Ryan Direct).

Q. Based on your review, did the RFP include sufficient guidance and data for companies to adequately respond to MERC's needs?

A. Yes. Based on my review, the RFP documents were sufficiently detailed and included two Project sizes to allow for full Project comparison between the incumbent pipeline, NNG, and the other bidders.

Q. Did the RFP allow respondents adequate time to respond?

A. Yes. The RFP requested responses two weeks after the date of issuance. Industry practice varies considerably depending on the level of complexity and other factors, but the two week timeframe would allow responses or, at a minimum, indications of intent from potential parties.

Q. Did MERC receive multiple responses?

A. Yes. NNG, NBPL, and Twin Eagle responded to the RFP.

Q. Were the responses received within the requested timeframe?

A. Yes. Mr. Sexton, a consultant for MERC, stated that initial proposals were received on January 16, 2015 and, after discussion with MERC, each party that provided a proposal was able to provide an update on February 18 and 19, 2015. MERC Ex. ___ at 41 (Sexton Direct).

Q. Were there multiple bid options?

A. Yes. Given that NNG is the incumbent pipeline serving MERC in the Rochester Area, the RFP included two scenarios. First, the request was made for 100,000 Dth/day of firm delivery entitlement to a new MERC TBS. The second option was to work with NNG to provide an incremental 45,000 Dth/day of firm capacity to the existing Rochester TBSs in addition to the NNG capacity currently contracted for delivery to those points to get Rochester to the desired entitlement.

Q. Do you address the aggregate volume and growth estimates provided by the Company?

A. No, these issues are addressed in the Direct Testimony of Adam Heinen.

Q. Did the Department have access to the RFP responses?

A. Yes. MERC provided the RFP responses in the MERC's **Highly Sensitive Trade Secret** Supplemental Response to OAG IR No. 132. **Highly Sensitive Trade Secret** DOC Ex. ____at MR-6, Attachment_OAG_132_Responses_HIGHLY SENSITIVE TRADE SECRET.pdf (Ryan **Highly Sensitive Trade Secret** Direct).

Q. Did you review MERC's comparative evaluation of the competitive bids?

A. Yes. MERC provided its internal review of the competitive bid process in MERC's **Highly Sensitive Trade Secret** Response to DOC IR No. 38. **Highly Sensitive Trade Secret** DOC Ex. ____at MR-1, Attachment_DOC_38_HIGHLY SENSITIVE TRADE SECRET.pdf (**Highly Sensitive Trade Secret** Ryan Direct). MERC's document was a high level summary of the pricing provided by suppliers along with other non-quantitative aspects that were factored into the Company's decision. All categories were weighted with Project cost holding the majority of the weight.

Q. Did you have any reason to question weights MERC assigned based on the information provided in MERC's baseline summary document of the RFP results?

A. No. The information and weights to each category appeared reasonable. Overall, the driving component was cost and the summary data confirms the decision made by MERC.

Q. Did MERC undertake any independent review of its RFP process?

A. Yes. MERC enlisted the services of Mr. Sexton to independently review the RFP process.

Q. Did the Company provide the results of Mr. Sexton's analysis and have you had an opportunity to review this analysis?

A. Yes on both counts. MERC provided Mr. Sexton's independent evaluation in MERC Ex. ___ at TCS-3 (Sexton Direct). Mr. Sexton's comparison focused solely on pricing and reached the same conclusion as MERC that the results of the RFP indicate that

NNG was the most competitive option for moving forward with the Rochester Expansion.

Q. Did you have any reason to question the information provided in Mr. Sexton's independent analysis?

A. No. In reviewing Mr. Sexton's analysis, I was able to tie his statements to the responses provided by the bidding parties and follow the calculations. Mr. Sexton's assumptions and additional cost component calculations are accurate.

Q. Additional components were negotiated with NNG after the formal RFP process was closed. Should the other bidders been offered the ability to offer further enhancements to their bids?

A. Given that NNG was the most competitive bid based on its Proposal 3.0, and given that the enhancements "continued to show significate savings over the life of the project", it was not unreasonable that the other bidders were not allowed to refresh proposals. MERC Ex. ____ at 51 (Sexton Direct). NNG Proposal 3.0 was received on February 18, 2015 with the competitive bids of the other pipelines and was the basis for negotiations and later amendments. The amended option also offered a phased approach, enabling MERC to partially delay cost of the expansion capacity until November 2019, which, based on Mr. Sexton's calculation, resulted in a net present value savings as compared to Proposal 3.0. MERC Ex. ____ at 45 and 46 (Sexton Direct).

Q. Did the negotiated enhancements to Proposal 3.0 create any additional obligation or cost for MERC?

A. Yes. The final Amended Negotiated Transaction with NNG increased the total cost of the Project in nominal dollars due to pushing out Phase 1 of the Project to November 1, 2018 instead of November 1, 2017. This delay resulted in an increased capital cost of approximately $2.5 million or less than 5 percent. MERC Ex. ___ at 15 (Mead Direct). These capital cost increases did not have a material impact on the results of the RFP process; more importantly, NNG would still have prevailed relative to the other bids.

Q. Were there additional components that made NNG the best option?

A. In addition to NNG providing the most cost competitive bid, the incumbent interstate pipeline company was able to differentiate itself by its ability to serve Rochester at multiple points, by having the least amount of pipeline mileage dependent on one pipeline and by capping the reservation price of NNG capacity so that it does not increase if NNG files for increased tariff rates. This information was provided in the Company's **Highly Sensitive Trade Secret** Response to DOC IR No. 38. **Highly Sensitive Trade Secret** DOC Ex. ___at MR-1, Attachment_DOC_38_HIGHLY SENSITIVE TRADE SECRET.pdf (**Highly Sensitive Trade Secret** Ryan Direct).[1]

[1] In conversation with MERC, the testimony above was deemed public. However the supporting Attachment_DOC_38_HIGHLY SENSITIVE TRADE SECRET.pdf remains Highly Sensitive Trade Secret.

Q. What additional enhancements did MERC receive from the final Amended Negotiated Transaction, and how do these enhancements benefit MERC ratepayers?

A. The negotiated enhancements added flexibility and certainty to extension rights as follows:

1. Fixed delivery rates for the existing Rochester entitlement: Instead of the rates being subject to change when NNG's maximum tariff rates change, MERC negotiated that the existing Rochester entitlement would be fixed at the current maximum rate during the 25-year term of the agreement. MERC Ex. ___ at 47 and 48 (Sexton Direct).
2. Firm growth capacity rights to other MERC markets: The negotiated agreement includes an additional 5,439 Dth/day of firm delivery to nine MERC delivery points and an additional 2,593 Dth/day of firm delivery to twenty-one MERC delivery points for Phase I and Phase II, respectively. MERC Ex. ___ at 48 (Sexton Direct). The firm capacity will be at NNG's maximum tariff rate.
3. Flexibility to use Rochester TF entitlement to serve markets other than Rochester: MERC is allowed to direct a portion of the firm Rochester entitlement to alternate MERC delivery points within NNG market zone EF on an alternate basis at the fixed rate. MERC Ex. ___ at 49 (Sexton Direct). The NNG market zone EF covers all of Minnesota. MERC is able to use up to 20% of the total Rochester capacity throughout the state. MERC Ex. ___ at 22 (Mead Direct). To clarify, ratepayers throughout the entire MERC system could benefit from MERC's flexibility to use the Rochester entitlement unless the delivery points are physically constrained. MERC Ex. ___ at 24 (Mead Direct). MERC provided a listing of delivery points, and included contracted capacity versus physically delivery capacity. MERC

defined "not physically constrained" as a TBS that has less contracted capacity than NNG's pipeline is physically capable of delivering. DOC Ex. ___at MR-7 (Ryan Direct) (MERC Response to OAG IR No. 185- Attachment OAG 185.xlsx).

4. Additional growth up to 2,000 Dth/day: The negotiated MERC and NNG agreement may also benefit ratepayers by improving system reliability, in that it provides MERC the option to purchase up to 2,000 Dth/day of additional capacity during any odd year of the agreement. The capacity would have a predetermined Capital Recovery Rate for NNG, but give MERC some flexibility if additional incremental capacity is needed. MERC Ex. ___ at 50(Sexton Direct).
5. A one-time five-year extension right at fixed rates upon completion of the 25-year contract: The final enhancement offered could benefit MERC ratepayers via the option to extend the contract at fixed discounted rates. The fixed rate would offer certainty of pricing and would not be subject to the applicable tariff rates at the time of the extension. MERC Ex. ___ at 50(Sexton Direct).

Q. Given your experience with gas contracts, what do you conclude?

A. I conclude that MERC's RFP process was fair and reasonable, and that MERC negotiated reasonable provisions for ratepayers not only in Rochester, but in other areas of MERC's system as well.

V. SUMMARY OF RECOMMENDATIONS

Q. Based on your investigation, what do you recommend?

A. Overall, I concur with Mr. Sexton's Direct Testimony in regards to the RFP conducted by MERC. I believe that the RFP process was a comprehensive gauge of the market and the potential alternatives for interstate pipeline services to the Rochester TBSs. While other pipelines may have difficulty serving Rochester, MERC made reasonable efforts to address this issue through the timing of the process and allowing other bidders the opportunity to provide competitive bids on the Project.

Q. Do you have any additional recommendations?

A. No.

Q. Does this conclude your Direct Testimony?

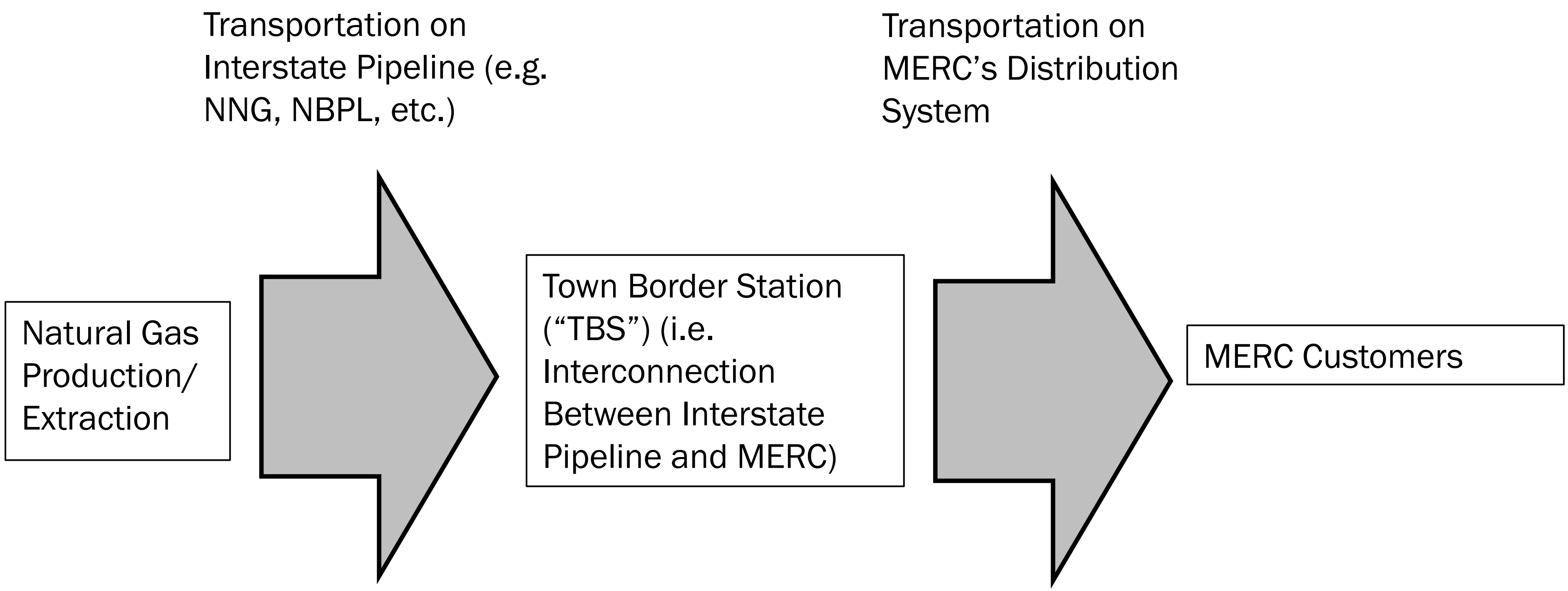
A. Yes.

SUMMARY OF ATTACHMENTS TO THE DIRECT TESTIMONY
OF MICHAEL RYAN

Attachment	Description	Pages
MR-1	**Highly Sensitive Trade Secret** MERC Response to DOC Information Request No. 38, Attachment_DOC_38_HIGHLY SENSITIVE TRADE SECRET.pdf	1
MR-2	DOC Exhibit___	1
MR-3	MERC Response to OAG Information Request No. 176	1
MR-4	MERC Response to DOC Information Request No. 44	2
MR-5	MERC Response to OAG Information Request No. 132, Attachment_OAG_132_RFP.pdf	5
MR-6	**Highly Sensitive Trade Secret** MERC Response to OAG Information Request No. 132, Attachment_OAG_132_Responses_HIGHLY SENSITIVE TRADE SECRET.pdf	120
MR-7	MERC Response to OAG Information Request No. 185, Attachment OAG No. 185.xls	1

Attachment_DOC_38_ TRADE SECRET DATA HAS BEEN EXCISED

Table 1. Flow of Natural Gas to MERC Customers



Docket No. G011/M-15-895
DOC Ex. ___ MR-2
Page 1 of 1

OAG No. 176

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:	Joseph A. Dammel	**Date of Request:**	May 6, 2016
Telephone:	(651) 757-1061	**Due Date:**	May 18, 2016

<u>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.</u>

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

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: 5/6/2016

Requested From: Minnesota Energy Resources Corporation Response Due: 5/18/2016

Analysts Requesting Information: Michael Ryan/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.	
44	Subject: RFP Reference: Sexton Direct Testimony, Page 38, Line 20 In the above reference, Mr. Sexton states, "all active pipeline companies operating in the general vicinity of Rochester, Minnesota." Alliance Pipeline is in not listed in Mr. Sexton's testimony. Please clarify whether Alliance was contacted regarding the proposed Project. Please provide information on Alliance's response or rationale for not including Alliance in the RFP process. If this information has already been provided in written comments, testimony, or in response to an earlier DOC information request, please identify the specific cite(s) or DOC information request number(s). MERC Response: Alliance Pipeline is a "wet" pipe, which means it transports un-processed natural gas liquids (NGL's), which includes propane, ethane, butane, etc., in addition to natural gas. Alliance Pipeline transports NGL's from Alberta, Canada to the Chicago/Joliet area, where the NGL's are "processed" to strip out the propane, ethane, butane, etc. from the NGL's producing pipeline quality "dry" natural gas. This pipeline quality "dry" natural gas enters a number of

Response by: Sarah R. Mead

Title: Manager of Gas Supply

Department: Gas Supply

Telephone: 920-433-7647

List sources of information:

other natural gas pipelines in the Chicago/Joliet area which transport the natural gas to various markets in the Midwest.

Transporting natural gas to Rochester, Minnesota via an interconnect with Alliance Pipeline would require Alliance Pipeline to build a processing plant to provide pipeline quality “dry” natural gas to the Rochester area. The expected cost of building a processing plant and operating it in a production environment made this option cost prohibitive and logistically un-feasible.

Alliance was not contacted directly about the project due to the additional “processing” costs and flow characteristics they would have had to manage to provide the relatively small volumes of pipeline quality “dry” natural gas to the Rochester area. However, the RFP was posted on MERC’s website and was, consequently, available to Alliance if it wanted to bid.

A consultant working on behalf of Alliance Pipeline did make an inquiry to MERC about the RFP, but Alliance Pipeline declined to bid on the project.

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

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:**

Docket No. G011/M-15-895
DOC Ex. ___ MR-6
Original Document Contains 120 Pages
PUBLIC

Attachment_OAG_132_Responses_TRADE SECRET DATA HAS BEEN EXCISED

OAG No. 185

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:	Joseph A. Dammel	**Date of Request:**	May 6, 2016
Telephone:	(651) 757-1061	**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: Mead Direct, at 24.

MERC states that "upgrading Rochester's infrastructure and providing additional capacity on the NNG system helps free up capacity that can be used by customers at other delivery points on the system, that are not physically constrained." Explain what is meant by the term "not physically constrained." Provide a list of TBSs that are not physically constrained as well as a list of TBSs that are physically constrained. Include the total capacity for firm delivery at each TBS, the amount of capacity available to MERC at each TBS, and whether the TBS is located "in the path" according to the PA with NNG for the new capacity (i.e., whether the alternate TBS is within the primary receipt and delivery points).

MERC Response:

The phrase "not physically constrained" refers to a TBS that has contracted capacity less than its physical delivery capacity. Please see Attachment OAG 185.xlsx for the remainder of the information requested.

Response by **Lindsay K. Lyle**
Title **Engineering Manager**
Department **Engineering**
Telephone **(651) 322-8909**

BEFORE THE MINNESOTA OFFICE OF 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

IN THE MATTER OF THE APPLICATION OF MINNESOTA ENERGY RESOURCES CORPORATION FOR AUTHORITY OF RIDER RECOVERY FOR THE ROCHESTER NATURAL GAS EXTENSION FOR NATURAL GAS SERVICE IN MINNESOTA	MPUC Docket No. G011/M-15-895 OAH Docket No. 68-2500-3319

DIRECT TESTIMONY OF ADAM J. HEINEN

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

REVIEW OF NEED, RIDER RECOVERY, AND FINANCIAL ISSUES

JULY 1, 2016

DIRECT TESTIMONY OF ADAM J. HEINEN
IN THE MATTER OF OF THE APPLICATION OF MINNESOTA ENERGY RESOURCES CORPORATION FOR AUTHORITY OF RIDER RECOVERY FOR THE ROCHESTER NATURAL GAS EXTENSION FOR NATURAL GAS SERVICE IN MINNESOTA

MPUC Docket No. G011/M-15-895
OAH Docket No. 68-2500-3319

TABLE OF CONTENTS

Section **Page**

I. INTRODUCTION 1

II. PURPOSE AND SCOPE OF TESTIMONY 1

III. PROJECT BACKGROUND AND DESCRIPTION 3

IV. SUMMARY OF MERC'S NEED FORECAST METHODOLOGY 6

V. DEPARTMENT REVIEW OF MERC'S NEED ANALYSIS 13
   A. Concerns with MERC's Need Analysis 14
   B. DOC Alternative Analysis 25

VI. PROJECT ELIGIBILITY FOR RIDER RECOVERY 37

VII. MITIGATION OF CAPACITY COSTS 46

VIII. RATE RECOVERY 49

IX. OTHER FUNDING POTENTIALLY AVAILABLE FOR THIS PROJECT 50

X. SUMMARY, RECOMMENDATIONS, AND CONCLUSIONS 58

I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Adam J. Heinen. I am a Public Utilities Rates Analyst with the Minnesota Department of Commerce, Division of Energy Resources (Department or DOC). My business address is 85 7th Place East, Suite 500, Saint Paul, Minnesota, 55101.

Q. What is your education and professional background?

A. A complete summary of my educational and professional background is presented in DOC Ex. ____ at AJH-1 (Heinen Direct). I have been a Public Utilities Rates Analyst with the Department since January 2007.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. What are your main responsibilities in this proceeding?

A. My responsibilities in this proceeding include analyzing Minnesota Energy Resources Corporation's (MERC or Company) proposed project and its associated need including its estimate of sales and peak demand, methods for mitigating potential excess capacity costs, and potential availability of other funding to offset the amount of the cost of the project to be charged to MERC's ratepayers. I respond to the testimony of Mr. Clabots and Ms. Lee.

Q. Do you address the Request for Proposal (RFP) process used by MERC when selecting its preferred project?

A. No. The review of the reasonableness of the RFP process is discussed in the Direct Testimony of Department Witness Michael Ryan.

Q. Do you address the apportionment of revenue responsibility associated with the Company's rider proposal, both in Rochester and outside of Rochester?

A. No. Department Witness Sue Peirce addresses the apportionment of revenue responsibility associated with the rider proposal. However, in assessing the need for the project, I identify certain needs within Rochester and recommend how to address those circumstances.

Q. Did the Commission provide guidance as to the issues it wants reviewed in testimony?

A. Yes. In its February 8, 2016 *Order and Notice of Hearing* (*Order*) the Commission listed three issues that it wanted parties to address. DOC Ex. ____ at AJH-2 (Heinen Direct). In relevant part the Commission stated the following:

> 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 Commission will defer any decision on the accuracy of MERC's revenue-deficiency calculation until the Company seeks approval of an NGEP rider to recover that revenue deficiency.

Q. Please summarize how your testimony is organized.

A. My testimony is arranged as follows:

- Project Background and Description;
- Summary of MERC's Need Forecast Methodology;
- Department's Review of MERC's Need Analysis;
  - o Concerns With MERC's Need Analysis;
  - o DOC Alternative Analysis
- Project Eligibility for Rider Recovery;
- Mitigation of Capacity Costs;
- Ratepayer Recovery;
- Other Funding Available for this Project; and
- Summary, Recommendations, and Conclusions.

III. PROJECT BACKGROUND AND DESCRIPTION

Q. Please summarize and describe the nature of MERC's proposed Project.

A. The Company's project (Rochester Project or Project) involves upgrading MERC's local distribution network in the Rochester Area,[1] improvements to Northern Natural Gas' (NNG) interstate pipeline delivery capacity to the Rochester Area, reconstruction of the Town Border Stations (TBS) that serve Rochester, and construction of transmission infrastructure to deliver additional capacity to the Rochester distribution system. MERC's project is split into two phases. Phase I has already been constructed and its recovery is included in the Company's pending general rate

[1] The Rochester Area can be defined as the City of Rochester and associated Town Border Stations in Southeast Minnesota served by MERC.

(Docket No. G011/GR-15-736 or 2015 Rate Case). Phase I involves upgrades to deliverability on MERC's distribution system in the Rochester Area.

Phase II involves reconstruction of the TBSs that serve Rochester and construction of the transmission infrastructure necessary to move additional capacity into the Rochester area. The costs associated with Phase II are proposed by MERC to be eligible for rider recovery authorized by the Natural Gas Expansion Project Statute.[2]

Q. When did MERC first notify the Department of its intention to pursue expansion of natural gas service in the Rochester Area?

A. MERC did so on or about October 22, 2014. In its Response to DOC Information Request (IR) No. 48, MERC provided all documents and presentations that it has made to parties regarding the need to expand service in the Rochester Area. DOC Ex. ____at AJH-5 (Heinen Direct). This information shows that the Department was first notified of the need for expansion in Rochester on, or about, October 22, 2014.

Q. Is the Project as currently proposed similar to the initial project plans discussed by MERC on October 22, 2014?

A. The goals of the Project have not changed since the October 2014 presentation; however, the Company's current plan to increase capacity is different than the potential projects shown to the Department in the planning phase. For example, in its October 2014 presentation, MERC anticipated total project costs upwards of $170 million, not including contingencies, which is significantly greater than the

[2] Minnesota Statute Section 21B.1638.

approximately $60 million in projected Northern Natural Gas project costs noted by the Company in this Docket. DOC Ex. ____at AJH-5 (Heinen Direct) and MERC Ex. ____at 2 (Lee Direct). Through discussions with the Department and other state agencies, MERC worked over time to streamline and improve its proposed project, including issuing an RFP and negotiating with counterparties to lower construction and capacity costs, as discussed further in Department witness Michael Ryan's testimony. The efforts of MERC, the Department, and other state agencies prior to the filing of this proposal have already saved ratepayers millions of dollars in project costs. These negotiations also resulted in improved terms and better flexibility for MERC and its ratepayers, as discussed further in Michael Ryan's testimony.

Q. How does this Project differ from past natural gas expansion projects intended to increase capacity in a given geographic area?

A. From an operational standpoint, this Project is not meaningfully different apart from its relative size. However, the Company's proposed rate recovery mechanism is different. MERC proposes to recover part of the construction costs as authorized by Minnesota Statute section 216B.1638, which is titled the Recovery of Natural Gas Extension Project Costs (NGEP). This filing marks the first time that a gas utility has sought rate recovery under this new Statute, which was enacted in 2015.

Q. Please explain how Minnesota Statute section 216B.1638 treats cost recovery.

A. If the proposing utility can show that costs are reasonable and prudent, this Statute allows a gas utility to recover up to 33 percent of annual project costs through a rider. Those costs in the rider are then "rolled" into rate base, along with the other

67 percent of costs, in a future general rate case. The costs in the rider are associated with extending, or expanding, service to an "unserved or inadequately served area," which is defined as: "an area in this state lacking adequate natural gas pipeline infrastructure to meet the demand of existing or potential end use customers." Minnesota Statute section 216B.1638, subd.1 (i). The Statute also states that the rider "shall include all of the utility's customers, including transport customers, to recover the revenue deficiency from a natural gas extension project." As discussed further below, I note that this aspect of cost recovery is important to avoid giving MERC's large customers an undue incentive to switch to transportation service solely to avoid the costs of this Project.

IV. SUMMARY OF MERC'S NEED FORECAST METHODOLOGY

Q. Please summarize the process MERC used to forecast need in this proceeding.

A. MERC used a two-stage process to forecast need for its Project. The Company first used historical data over the period January 2007 to July 2015 to forecast sales and customer counts, by individual rate class, from August 2015 through December 2025. MERC next used heating season data (December through February) over the period from December 2012 to February 2015 to estimate firm peak load at each of the TBSs in the Rochester Area.

The Company then applied the retail growth rate calculated in the firm sales models to estimate growth in firm peak load into the forecasting period. In other words, the expected growth in firm peak demand was driven by the results of the firm rate class sales forecasts. MERC Ex. ____ Attachments C8 through C18. (Initial Filing).

Q. Which Company witness addresses the Company's forecasting method in this proceeding?

A. MERC's need forecast is presented in the Direct Testimony of Company Witness Mr. David Clabots. This testimony includes a discussion of MERC's sales forecasting approach and peak demand forecasting approach. MERC Ex. ____at 4-7 (Clabots Direct).

Q. Before delving into the specifics of the Company's various regression models, do natural gas utilities typically produce medium to long-range forecasts?

A. From a regulatory standpoint, no they do not. Unlike electric utilities in Minnesota, which are required by Minnesota Statute section 216B.2422 and Minnesota Rules Chapter 7842 to regularly file integrated resource plans, Minnesota regulated natural gas utilities are not subject to Commission review of their long-range expansion plans, procurement plans, or expected growth. This marks the first time that a gas utility has filed a long-range sales forecast during my tenure at the Department. This fact points to another reason why the Project is unusual, as I discuss further below.

Q. Please briefly explain how MERC estimated sales in this proceeding.

A. MERC used Ordinary Least Squares (OLS) to estimate use per customer (UPC) or sales for its various rate classes. The Company used heating degree days (HDD), monthly factors, trend factors, autoregressive terms, and economic and demographic data, dependent upon the individual rate classes, to estimate UPC or sales. For the UPC models, MERC estimated customer counts using trend factors and autoregressive terms. Generally, MERC used a method similar to the one it used for the short-term sales forecast in the Company's 2015 Rate Case.

Q. Above you mentioned peak forecasts. Did MERC conduct a peak demand forecast in any recent regulatory filings?

A. Yes. The Company estimated firm peak demand for its Purchased Gas Adjustment (PGA) systems in its most recent annual demand entitlement filings (Docket Nos. G011/M-15-723, G011/M-15-724, and G011/M-15-724). These filings focus on the amount of existing pipeline capacity to reserve to serve the gas-supply needs of firm sales customers. In these filings, the Company used daily data for the 2012, 2013, and 2014 heating seasons to determine the relationship between weather (defined as adjusted HDDs or AHDDs) and firm throughput. MERC then used the results of these regression analyses to predict firm throughput on a day with AHDDs similar to the coldest day experienced on the MERC system. The Company concluded this analysis by applying statistical-based risk factors to each regression models to better estimate peak day throughput.

The planning objective in demand entitlement proceedings is ensuring that MERC can provide service in the coldest 24-hour average wind adjusted HDD (AHDD) day for each regression area. For the Rochester area, the coldest AHDD day occurred in 1996 and it was 101 AHDD, or approximately an average daily adjusted temperature of minus 36 degrees Fahrenheit.

Q. What is peak demand?

A. In simple terms, peak demand represents the maximum daily natural gas throughput on a utility's system. However, peak demand as it relates to this docket and to demand entitlement filings is slightly different. As noted above, when a utility estimates peak demand for demand entitlement purposes, it focuses only on throughput for firm sales customers. It does not include interruptible load in this analysis because interruptible customers receive the benefit of lower non-gas margins knowing that they will be interrupted if load must be curtailed to maintain system integrity. Transportation load is also not included in estimates of peak day demand for demand entitlement purposes because these customers procure their entitlement level through a third-party vendor, not the gas utility.

Q. Why is peak demand different in this proceeding?

A. MERC's proposal in this proceeding is different because it proposes to change the existing capacity of the pipeline that serves the Rochester area, which means there is a different category of costs to consider – the costs that NNG will charge MERC to change the capacity serving the Rochester area, regardless of the type of customer that uses the incremental capacity. I discuss this issue further below.

Q. Please briefly explain how MERC estimated peak demand in this proceeding.

A. In the demand entitlement filing, the Company estimated peak demand for the Rochester area using a single regression model. DOC Ex. ___at AJH-6 (Heinen Direct). To assess need in this proceeding, MERC conducted individual regression models for each TBS in the Rochester Area and then used the coldest day planning objective and risk adjustments to determine current, or base, firm peak demand. MERC provided the results of its peak demand analysis for this proceeding in its response to DOC IR No. 16. DOC Ex. ____at AJH-7 (Heinen Direct).

Q. Did MERC use the same basic estimation methodology for its peak demand forecast in this proceeding that it employed in its most recent demand entitlement filings?

A. Yes and no. Both analyses used OLS regression and daily heating season throughput data over the period from December 2012 to February 2015; however, the model specifications are not the same.

Q. How did MERC specify weather in the forecasting period?

A. The Company specified and normalized weather in the forecasting period differently for the sales and peak demand forecast. This difference is not surprising given the design and purpose of the two analyses. The Company assumed normal weather in its UPC and sales models. MERC calculated and defined normal weather in the same manner as it did in the rate case, which was based on average monthly HDDs, for the Rochester area weather station, over the 20-year period from January 1995 to December 2014. I reviewed these normal weather data and confirmed that the data agreed with what was provided in the 2015 Rate Case. As noted above, for the peak day analysis, MERC used the coldest daily AHDD value for the Rochester area as its planning objective. In a basic sense, the sales forecast attempted to remove the impacts of non-normal weather, while the peak demand model attempted to determine throughput on the day with the most impact from weather.

Q. How did the Company account for the Mayo Clinic Destination Medical Center (DMC) in its sales and demand forecasts?

A. MERC's sales and demand projections did not explicitly account for potential growth associated with the DMC. The Company's sales and demand projections generally assumed that the DMC would not exist in the future period because the projections relied upon historical data, without adjustments in the forecasting period, to estimate future sales and load. MERC Ex. ____ at 13(Clabots Direct). The impacts of the DMC would only be implicit because the Company included regional demographic and economic factors when it estimated and forecast sales for certain rate classes. As discussed further in Section V below, the demographic data included in the forecasting period appeared to account, at least in part, for expected growth in the Rochester area during the forecasting period.

Q. What are the final results of MERC's need forecast?

A. The results of the Company's forecast need were provided in its responses to DOC IR Nos. 16 and 18. DOC Ex. ____at AJH-7 and AJH-8 (Heinen Direct).

Q. Are you aware of any other information regarding drivers for the need for this project within Rochester?

A. Yes. I reviewed the City of Rochester's Proclamation along with the "2015 Update of the [Rochester Public Utility] RPU Infrastructure Study" published in June 2015 by Burns and McDonnell for RPU (RPU Infrastructure Report). DOC Ex. ____at AJH-3 and AJH-4 (Heinen Direct).

The Proclamation, which was issued by Mayor Ardell Brede on October 12, 2015, and does not appear to be binding, requests that the City of Rochester apply for funding to develop a comprehensive energy plan. As part of this energy plan, the Proclamation envisions analysis about the feasibility of using renewable electricity, among other things, for heating, cooling, and the transportation sector.

The RPU Infrastructure Report discusses renewable generation but places significant emphasis on the importance of natural gas for electric generation, potentially including the replacement of existing generating facilities in the Rochester Area. As discussed in greater detail below, the Rochester area is capacity-constrained in terms of natural gas. Given this fact, along with RPU's plan to use increasingly more natural gas for electric generation, and the importance of ensuring reliable natural gas and electric service, I note that RPU's needs are an important factor to consider in this proceeding.

Finally, it is unclear how RPU intends to procure service, but it was announced recently that RPU plans to rebuild its Westside Energy Station and use natural gas as its fuel source. DOC Ex. ____ AJH-25 (Heinen Direct).

Q. What information does the RPU Infrastructure Report indicate about RPU's possible use of natural gas in the future?

A. The RPU Infrastructure Report indicates that RPU: a) already has a shortfall to meet electric capacity needs, b) already switched to natural gas to meet the steam contract with Mayo, c) is considering developing a combined heat and power facility powered by natural gas and d) expects to need a combined cycle natural gas facility in the future. The RPU Infrastructure Report further observed the following:

> Historically, natural gas-fired power plants were dispatched during the summer to meet increased demand due to air conditioning needs, when there is little competition for natural gas supply and deliveries. However, with the increased coal-fired power plant retirements, more natural gas-fired generation is going to be required during winter months when increased natural gas demand is prevalent due to residential and commercial heating needs. As such, many of the independent system operators are evaluating the overall reliability of the bulk electric system, especially during winter months, with increased reliance on natural gas-fired power plants. If firm natural gas deliveries are required for power generators, it could increase the cost of production significantly.

DOC Ex. ____at AJH-4, p. 3-2 and 3-3 (Heinen Direct)

V. DEPARTMENT REVIEW OF MERC'S NEED ANALYSIS

Q. Were you able to review and verify the Company's model outputs for the sales and peak demand models?

A. Yes. I was able to replicate MERC's regression results using its input data and model specifications.

Q. Did you observe any issues or concerns with MERC's forecast methodology?

A. Yes. I observed several issues with the Company's methodology to estimate need in this proceeding. These issues may call into question the validity of the Company's underlying need for this project. Since the Company's estimation of need was sequential (*e.g.,* firm peak demand contingent upon projected firm sales), I identify and address each of these issues separately below and in the order they occurred in MERC's analysis.

Q. Given these issues, did you attempt to independently verify the reasonableness of the Company's proposed need?

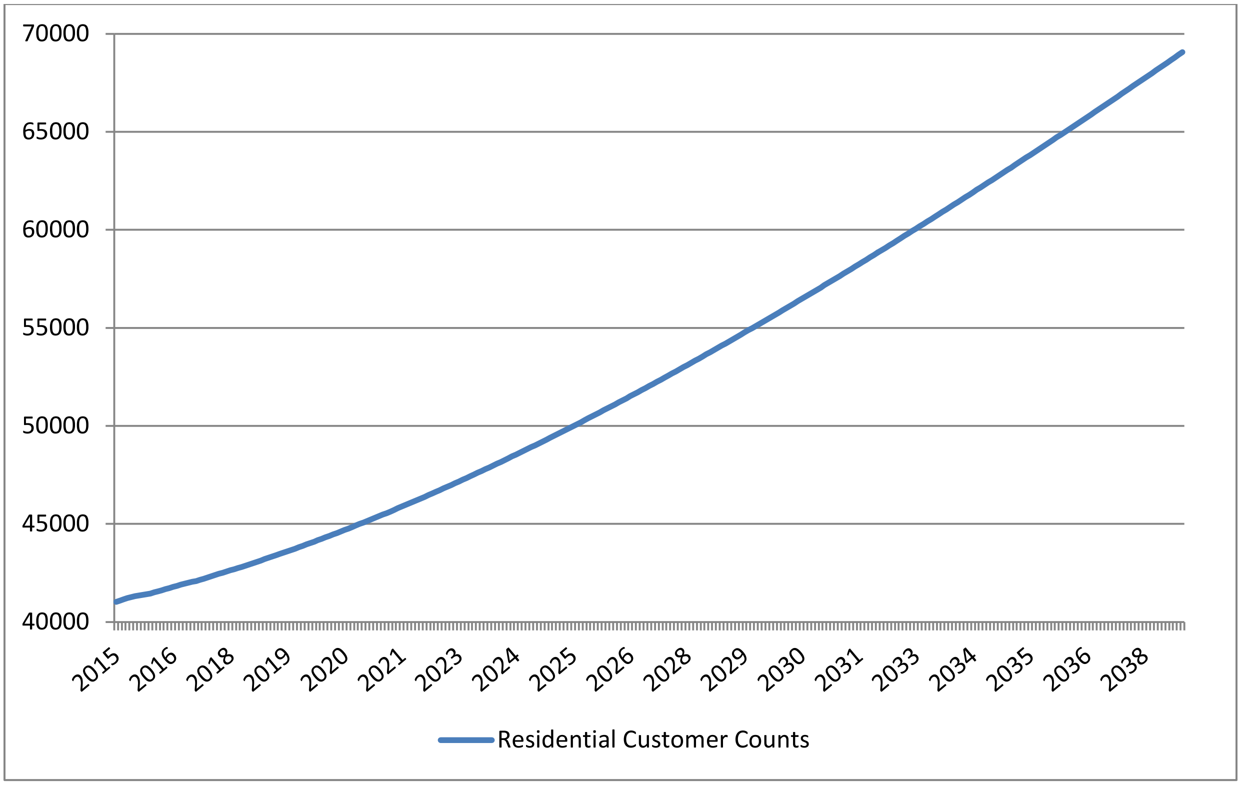
A. Yes. I discuss this independent analysis in greater detail in Section IV.B below.

A. CONCERNS WITH MERC's NEED ANALYSIS

Q. What is the first issue, or area of concern, you identified in the Company's analysis?

A. As noted above, MERC's estimates of sales growth for the Residential and Small Commercial/Industrial rate classes were based on use per customer (UPC) models. The use of UPC models required MERC to forecast customer growth into the forecasting period. While analyzing the Company's customer count forecasts, I observed that MERC used trend factors and autoregressive terms to estimate customer counts in the forecast period. The results of the Company's Residential customer growth model are plotted in Graph 1 below.

Graph 1: Residential Customer Count Forecast for the Rochester Area



The results of the Company's customer count forecast suggested that growth would increase significantly, over time, into the forecast period. For example, MERC's forecast assumed annual Residential customer count growth in the Rochester Area of approximately 2.26 percent. DOC Ex. ____at AJH-9 (Heinen Direct).

Q. How did these projected customer count figures compare to other growth projections for the area?

A. MERC provided population forecasts from the Rochester-Olmsted Council of Governments (ROCG) in its Direct Testimony. MERC Ex. ____at DWC-2, p. 7 of 14 (Clabots Direct). The ROCG population forecast data did not anticipate growth at the level projected by the Company. In fact, the highest average annual population growth assumed by ROCG for Olmsted County was approximately 1.50 percent, which is significantly lower than the average customer count forecast used by MERC.

Q. Are population growth estimates and customer count estimates entirely comparable?

A. No. Population looks at the number of people in a given area, while customer counts look, ostensibly, at the number of utility meters in an area. In many respects, customer counts for a utility are analogous to the number of households in an area.

Q. Do household data exist for the Rochester area?

A. Yes. The United States Census Bureau (Census Bureau) and Minnesota State Demographic Center (MN Demographer) collect and publish household data. DOC Ex. ____at AJH-10 (Heinen Direct). These data are compiled on a decadal or annual basis and make it possible to analyze the appropriateness of the Company's forecasting results relative to other growth forecasts.

Q. Please explain how you compared the results of MERC's residential customer count forecast to historical household data.

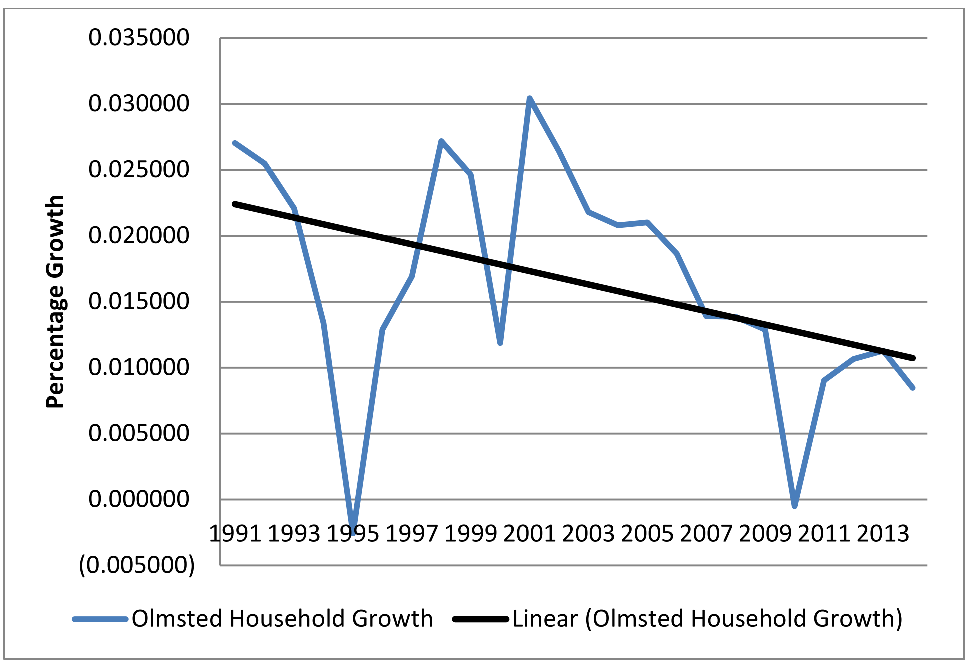
A. First, I used historical household data for Olmsted County Minnesota over the period from 1970 to 2010 from the 2010 Census and household data over the period from 1990 to 2014 from the MN Demographer to estimate historic household growth for the Rochester Area. DOC Ex. ____AJH-11 (Heinen Direct). Second, I compared historical household counts during this period to historical population numbers to determine whether a consistent relationship existed between households and population in the Rochester Area. Third, I compared historical household growth in

Olmsted County, on an annual percentage basis, to the average annual customer count growth during the forecast period that was used by MERC in its Residential rate class UPC forecast.

Q. Were you able to calculate average household growth in the Rochester Area?

A. Yes. Using historical data for Olmstead County, I estimated average annual household growth since 1990. DOC Ex. ____ at AJH-11 (Heinen Direct). The average growth rate is approximately 1.65 percent; however, there has been a downward trend in household growth over this period. Household growth since 1990 is shown in Graph 2 below.

Graph 2: Olmsted County Household Growth (1990-2014)



Q. Why is it necessary to analyze the historical relationship between household size and population?

A. If underlying changes in demographic data such as death rates or birth rates occur, they can impact the relative size of an average household. If this occurs, then it will be difficult to compare population and customer count forecasts because population will not effectively match household size, which is comparable to a utility customer.

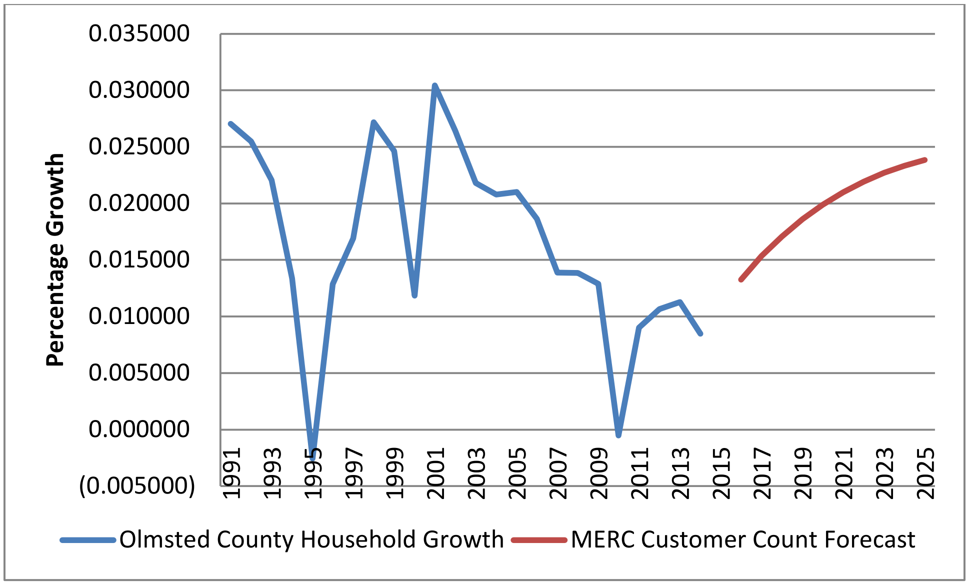
Q. Based on your review of historical demographic data, has average household size changed in the Rochester Area?

A. No, average household size has remained relatively constant at approximately 2.5 individuals per household since 1970. DOC Ex. ____ at AJH-10 (Heinen Direct). This fact means that it is reasonable to compare the RCOG's population growth estimates in DWC-2 to the Company's customer count forecast shown in Graph 1 above.

Q. How did MERC's customer count growth figures compare to historical household growth in the Rochester Area?

A. The average growth rate from MERC's forecast was comparable to household growth in the 1990s for the Rochester Area but noticeably higher than household growth over the past 10 years. DOC Ex. ____ AJH-11 (Heinen Direct). In other words, the Company's Residential customer count projections assumed significant increases in population and household growth, above current conditions. The Company's customer count forecast compared to historical household growth is illustrated in Graph 3 below.

Graph 3: Comparison of Historical Household Growth to MERC's Customer Count Forecast



Q. What did the increase in projected customer growth relative to current conditions suggest?

A. I note that, since the burden of proof is on MERC to demonstrate the need for the project, it will be up to MERC to explain this assumed increase. However, I also note that the Company's over-forecasting in this regard could be considered, at least temporarily, to be a placeholder for MERC's lack of inclusion of the DMC as discussed above. Moreover, as discussed above, there may be a need for increased use of firm natural gas to produce electricity, which MERC's forecast may encompass. I recommend that MERC address these issues in its Rebuttal Testimony.

Q. Do you believe that MERC's growth assumptions were reasonable?

A. Notwithstanding my response above, I am somewhat concerned that the Company's expected growth rate was noticeably greater than the RCOG population growth rate, considering the fact that the RCOG's forecast likely assumes implementation of the DMC. In addition, the current trend in household growth has been fairly long lasting, nearly 10 years, during a period of economic growth in the region,[3] and the overall success of the DMC and its implementation is still unclear. If the DMC does not come to fruition, is implemented slower than expected, or implemented in a manner different than currently envisioned, it is likely that MERC customer growth anticipated for the region will be lower than forecasted.

Q. What conclusions did you reach regarding the Company's projected customer growth forecasts and their impact on MERC's sales forecast?

A. Based on my analysis, I conclude that the Company's customer count projections may be considered at least temporarily as a placeholder for the lack of inclusion of the DMC as discussed above. While I recommend that MERC address this issue in their Rebuttal Testimony, for purposes of my analysis I assumed that MERC's projections represented the higher range of expected growth for the Rochester Area. This conclusion is supported further in Section V.B of this Direct Testimony.

Q. What is the second area of concern you identified in MERC's analysis?

A. The second area of potential concern was the Company's decision to use the growth rate from its sales forecast as the growth factor in its peak demand analysis. This decision assumed that changes in peak day usage, and expected changes in peak day usage, were the same or comparable to sales growth.

---

[3] The general health of the Rochester area economy relative to the State of Minnesota as a whole is discussed in the Direct Testimony of MERC Witness Clabots. MERC Ex. ____at 10-13 (Clabots Direct).

Q. Based on your review, did the Company provide data that confirmed that peak day usage and sales growth exhibited the same, or a similar, trend?

A. No, it did not. The only potential support was MERC's assumption that system design-day growth will be 1.5 percent, which was the same as the growth rate determined in the sales forecast. MERC Ex. ____ 25 (Mead Direct). This result could be considered to be confirmation because it appeared that MERC assumed the system design-day growth rate and did not explain how it derived this growth rate.

Q. Did the Company provide any discussion related to why it decided to tie these two analyses together?

A. Not specifically; however, the Company did provide extensive discussion regarding the data issues that MERC has regarding older data. In earlier rate case filings, the Department and other state agencies raised concerns regarding the appropriateness and validity of older data that was collected by MERC's predecessor company. As a result, the Company agreed to only use data beginning in January 2007. MERC Ex. ____at 5 (Clabots Direct). Since the Company's all-time peak day (101 AHDD) occurred in 1996, MERC did not have data available to estimate firm throughput from when the peak day occurred. In addition, the Company did not have firm specific, daily data available prior to the 2012 heating season because telemetry was not required of interruptible customers before this time. For these reasons, it appears that the Company tied the analyses together because of a lack of peak day data and the only ready means to estimate peak day growth was to use the results of the sales forecast.

Q. Did you examine past regulatory filings to determine whether the Company's assumed 1.5 percent design-day growth assumption was reasonable?

A. My analysis was complicated by the consolidation of MERC PGAs in July 2013, but I did examine historical MERC design-day filings to validate the Company's growth assumption. DOC Ex. ____at AJH-12 (Heinen Direct). Based on the information in the 2015 and 2012 demand entitlement filings, it was unclear if MERC's 1.5 percent growth rate was reasonable. In particular, it appeared that since 2010 growth in the design-day decreased on an annual basis. Prior to this time, it appeared that MERC's system exhibited relatively consistent design-day growth; however, during the current time frame growth rates have moderated and become more volatile. Based on current design-day growth trends, it appeared that a growth figure closer to 1.0 percent may be more appropriate.

Q. What did you conclude regarding the design-day growth figure?

A. I conclude that the Company did not provide evidence in this record supporting the reasonableness of its design-day growth figure. Therefore, without a reasonable estimate of design-day growth, I could not conclude that MERC's reserve margin analysis in Ms. Mead's Direct Testimony was representative of expected conditions during the forecasting period. MERC Ex. ____at 25 (Mead Direct). Given these concerns, I conducted an alternative reasonable margin analysis, which is presented in Section V.B below.

Q. What was the third area of concern you identified in the Company's analysis?

A. The third issue I identified was the presence of two separate peak demand forecasts. As noted above, MERC conducted a peak demand forecast in its annual demand entitlement filing and in this proceeding. Although the Company did not conduct a long range peak demand forecast in the annual demand entitlement filing, the peak demand analysis that was conducted in the demand entitlement filing was analogous to the base forecast MERC estimated in this proceeding. The presence of two peak demands being produced by the Company raises the question of which forecast is most appropriate for determining need in this proceeding.

Q. As noted above, the demand entitlement filing is meant to determine the appropriate amount of capacity to serve demand on a peak day for a given PGA area. If that is the case, then would the peak day forecast in the demand entitlement be different than the peak day forecast in this proceeding because the forecast in this proceeding is limited strictly to the Rochester area?

A. Not in this case. When estimating peak demand in its demand entitlement filing, MERC used separate regression models, by area, to determine peak demand for the NNG PGA area; in the demand entitlement filing one of the regions used was Rochester. DOC Ex. ____at AJH-6 (Heinen Direct). I examined the Rochester Area regression model in the demand entitlement filing and confirmed that the peak day planning objective of 101 AHDD, the same regression adjustments were used, and the input data was consistent between the two analyses. As such, it was possible to compare the expected results associated with both analyses.

Q. Are the results of the two forecasts the same?

A. No, they are not. The analysis used to determine need in this filing has different independent factors than the Rochester area regression analysis used in the Company's 2015 demand entitlement filing.

Q. What was the difference in expected peak day demand between the two forecasts?

A. The demand entitlement forecast appeared to be approximately 16,800 Dkt/day greater than the Company's projected peak demand forecast in this docket. Inclusive of regression adjustments, MERC projected peak demand in the demand entitlement filing is 106,050 Dkt/day and 89,251 Dkt/day in this proceeding. DOC Ex. ____ AJH-6 and AJH-7 (Heinen Direct)

Q. Did this difference have a significant impact on expected need for the proposed project?

A. Because the estimated base peak demand in the 2015 demand entitlement filing was greater than the base forecast in this proceeding, there is not a concern that the project as proposed by MERC in this proceeding is oversized.

Q. Did you attempt to independently verify base peak demand?

A. Yes. I used OLS regression to conduct a peak demand analysis using data over the period from January 2007 to February 2015. This analysis was based, in part, on the maximum daily AHDD for each month to estimate maximum daily peak load, on a monthly basis, for all of the TBSs in the Rochester area. The results of the regression analysis were then used to estimate peak load on a peak day, 101 AHDD, and adjusted to remove non-firm usage. This analysis resulted in a base peak consumption of approximately 90,000 Dkt/day, which was comparable to the estimate filed by the Company in this proceeding. DOC Ex. ____at AJH-13 (Heinen Direct). Despite the fact that MERC estimated two peak days, the result of this independent estimation confirm that base peak consumption used by MERC to establish need for this project was not unreasonable.

Q. Did you identify any additional concerns or issues that you wish to address?

A. No, I did not.

B. DOC ALTERNATIVE ANALYSIS

Q. Please explain why you offer an alternative analysis of need.

A. As noted in Section V.A above, I observed that the customer count forecast used by MERC in its need forecast may be too high. Given this concern, it was necessary to investigate customer growth in greater detail.

Q. Why are customer counts so important when determining need for this project?

A. The importance of customer counts is two-fold. First, the methodology used by MERC, as described above, underscored the importance of customer counts in the forecasting period. Second, firm consumption on a design-day or peak day, on a per customer basis, had been trending downward over time, so it was reasonable to assume that customer growth was the only factor driving the need for increased capacity; therefore, the reasonableness of customer counts in the forecasting period was unquestionable.

Q. Please explain in greater detail why the customer count forecast was important in terms of MERC's methodology.

A. As described above, the Company's methodology used the estimated growth rate from its sales forecast to increase demand consumption in the forecasting period. When forecasting sales or use per customer, the market standard is to assume normal weather in the forecasting period; in other words, weather is held constant in the forecasting period so that sales are approximated based on normal, or representative, weather conditions. I reviewed the Company's sales forecasting results and MERC employed a normal weather methodology. The Company's normal weather assumption resulted in constant use per customer in the forecasting period. MERC Ex. ____at Attachment C1 (Initial Filing). Since use per customer remained constant, increases in customer counts were the driver of forecasted sales growth. Therefore, if the growth in customer counts was too high, this would call into question whether the size of the proposed project was overstated.

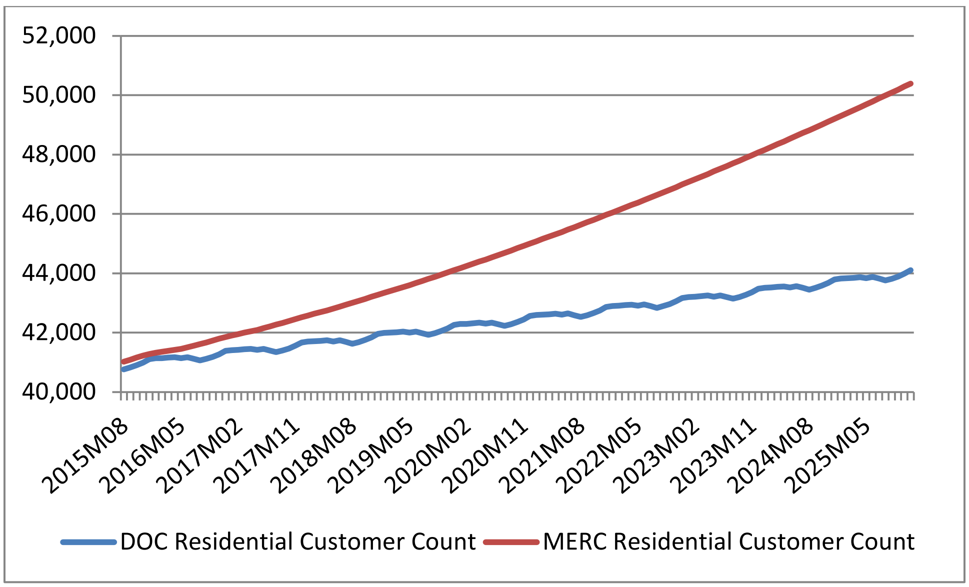
Q. How did you conduct your alternative customer count forecast?

A. I used OLS regression analysis as the basis for forecasting firm customer counts in the Rochester area. My analysis used monthly factors over the period from January 2007 to July 2015 and autoregressive terms to forecast Rochester area customer counts from August 2015 through December 2025. DOC Ex. ____at AJH-14 (Heinen Direct).

Q. What were the results of your customer count forecast?

A. My forecast results suggested an increase in retail customer counts of approximately 0.75 percent per year in the forecasting period, which was approximately 1.14 percent less than the Company's projections of 1.89 percent. The difference between the two forecasts is illustrated in Graph 4 below.

Graph 4: Comparison of DOC Residential Customer Count and MERC Residential Customer Count Forecasts



Q. What reasons may have driven the difference in results between your customer count forecast and the Company's customer count forecast?

A. The results of my forecast were based solely on historical MERC operations and only included a single autoregressive term. MERC's forecast, on the other hand, included several different autoregressive terms and a trend factor. Since the Company's trend factor had a positive value, it is possible that the trend factor was putting unnecessary upward bias on customer count growth.

Q. Were your customer counts reasonable despite the fact that they do not factor in potential growth factors such as the Destination Medical Center?

A. Yes. The full implementation of the DMC is currently speculative. It is unclear when, or to what level, the DMC or other developments may impact future growth in the Rochester Area. The results of my forecast, however, were not speculative and were rooted firmly in current trends for the Rochester Area since January 2007. My forecast results were also supported when compared to the average historical customer growth in the Rochester Area, as presented by the Company, and recent household growth figures for the Rochester Area. MERC Ex. ____at 10 (Clabots Direct) and DOC Ex. ____at AJH-11 (Heinen Direct).

Q. After comparing the Company's customer count forecast and your customer count forecast, what were your conclusions regarding these customer count projections?

A. Based on the assumptions inherent in both my customer count forecast and the Company's customer count forecast, it can be inferred that both forecasts were potentially acceptable but for different reasons. In the event that the DMC is implemented as planned or there is a greater need for natural gas to produce electricity, it is more likely that the Company's growth projections will happen, while, on the other hand, if the DMC is delayed or does not materialize, it is more likely that my forecast of growth will occur. Therefore, I conclude that it is reasonable to see my forecast as a status quo forecast or a lower bound projection, while MERC's projected growth represents an optimistic or upper bound forecast. This conclusion is further supported by the fact that the RCOG anticipates future population growth in

Olmsted County of between 1.00 percent and 1.50 percent on an annual basis. MERC Ex. ____at DWC-2, p. 7 of 14 (Clabots Direct).

Q. Since your forecast likely represented the lower bound for reasonable growth, did you conduct additional analysis to determine whether the project, as proposed, was reasonable at your forecast?

A. Yes. I used my customer count forecast results and applied those to the Company's UPC results to estimate future sales. I then used these results to estimate firm growth in the forecast period. Specifically, I used a growth figure of approximately 0.77 percent to estimate increased growth in the Company's base peak demand forecast instead of the 1.5 percent growth figure used in MERC's Direct Testimony. This revised peak demand forecast for the Rochester Area is shown in DOC Ex. ____at AJH-15 (Heinen Direct).

Q. What was the next step in your need analysis?

A. After estimating peak demand for the forecasting period, I re-created the reserve margin analysis shown in Ms. Mead's Direct Testimony to assess what impact the lower growth rate will have on Rochester Area and MERC-NNG system reserve margins. MERC Ex. ____at 25 (Mead Direct).

Q. Did you make any modifications to the Company's reserve margin analysis?

A. Yes. As noted in Sub-Section A above, it did not appear that the Company's assumption of 1.5 percent design-day growth was reasonable. I reviewed recent demand entitlement filings for the MERC-NNG and MERC-Northern PGA and concluded that recent trends in design-day growth have been less than 1.5 percent on an annual basis. DOC Ex. _____at AJH-12 (Heinen Direct). Based on information from these recent demand entitlement filings, it appeared that a 1.0 percent design-day growth rate was more reasonable.

Q. What were the results of your reserve margin analysis?

A. My analysis and calculations are provided in DOC Ex. ____at AJH-16 (Heinen Direct) and are summarized in Table 1 below.

Table 1: Comparison of Excess Capacity

	System Excess Capacity	
Year	MERC Excess Capacity (Dkt/day)	DOC Excess Capacity (Dkt/day) (Preferred Case)
2019	29,017	30,886
2020	44,874	49,965
2021	40,970	47,413
2022	37,007	44,836
2023	32,985	42,233
2024	28,902	39,604
2025	24,759	36,948
2026	20,553	34,266
2027	16,284	31,557
2028	11,950	28,821
2029	7,552	26,058
2030	3,088	23,267
2031	856	20,448
2032		17,601
2033		14,725
2034		11,821
2035		8,771
2036		8,013
2037		7,249
2038		6,479
2039		5,703
2040		4,921

Q. What conclusions do you draw from your reserve margin analysis?

A. The analysis showed that my updated growth assumptions result in slower peak day capacity growth in the Rochester Area and on the MERC system as a whole. This slower growth increased, and prolonged, the reserve margin concerns discussed by the Company in its Direct Testimony. MERC Ex. ____at 25 (Mead Direct). Instead of the excess capacity from the project being used in approximately 2030 as calculated by the Company, my analysis showed that some level of excess capacity will exist until the end of the forecasting period in 2040.

Q. Were you able to estimate the costs associated with this excess capacity?

A. Yes. Using the estimated annual capacity costs, provided in the Company's initial filing, I calculated the costs of excess capacity associated with the proposed project. MERC Ex. ____at 102 (Initial Filing). The costs of excess capacity are provided, on an annual and total basis in Table 2 below. I have also included the supporting calculations as an attachment to this Direct Testimony. DOC Ex. _____at AJH-16 (Heinen Direct).

Table 2: Comparison of Cost of Excess Capacity

Year	MERC Cost of Excess Capacity	DOC Cost of Excess Capacity (Preferred Case)
2019	$2,192,622	$2,333,898
2020	$5,783,419	$6,439,545
2021	$5,250,738	$6,076,514
2022	$4,696,232	$5,689,694
2023	$4,144,245	$5,306,131
2024	$3,579,281	$4,904,504
2025	$3,046,498	$4,546,377
2026	$2,501,582	$4,170,707
2027	$1,960,861	$3,800,089
2028	$1,417,554	$3,418,740
2029	$889,595	$3,069,372
2030	$359,757	$2,710,459
2031	$99,719	$2,382,066
2032	$0	$2,050,388
2033	$0	$1,715,394
2034	$0	$1,377,050
2035	$0	$1,021,813
2036	$0	$933,472
2037	$0	$844,449
2038	$0	$754,740
2039	$0	$664,339
2040	$0	$573,242
Total	$35,922,104	$64,782,983

As shown in Table 2 above, the excess capacity cost associated with the Department's forecast was approximately $30 million greater, through 2040, than MERC's filed forecast.

Q. If under your growth assumptions, which can be considered a low-growth scenario, excess capacity exists throughout the entire forecasting period, is it possible that a smaller project could satisfy the proposed need?

A. Potentially. However, the construction of a smaller project includes the risk that growth will be higher than expected and future expansions will likely be required. That being said, I did conduct a similar reserve margin analysis assuming the addition of 25,000 Dkt/day of incremental capacity and 35,000 Dkt/day of incremental capacity to Rochester. These results are provided in DOC Ex. ____at AJH-17 and AJH-18 (Heinen Direct) and are summarized in Tables 3 and 4 below.

Table 3: Comparison of Excess Capacity (25,000 Dkt/day Scenario)

Year	MERC Excess Capacity (Dkt/day)	DOC Excess Capacity (Dkt/day) (Preferred Case Assumptions)
2019	19,654	17,752
2020	13,931	13,931
2021	11,823	11,379
2022	10,619	8,802
2023	9,410	6,199
2024	8,196	3,570
2025	6,976	914
2026	5,752	0
2027	4,523	0
2028	3,289	0
2029	2,050	0
2030	806	0
2031	0	0
2032	0	0
2033	0	0
2034	0	0
2035	0	0
2036	0	0
2037	0	0
2038	0	0
2039	0	0
2040	0	0

Table 4: Comparison of Excess Capacity (35,000 Dkt/day Scenario)

Year	MERC Excess Capacity (Dkt/day)	DOC Excess Capacity (Dkt/day) (Preferred Case Assumptions)
2019	19,654	17,752
2020	21,931	21,931
2021	19,379	19,379
2022	16,802	16,802
2023	14,199	14,199
2024	11,570	11,570
2025	8,914	8,914
2026	6,232	7,340
2027	4,523	6,633
2028	3,289	5,920
2029	2,050	5,201
2030	806	4,477
2031	0	3,747
2032	0	3,012
2033	0	2,271
2034	0	1,524
2035	0	771
2036	0	13
2037	0	0
2038	0	0
2039	0	0
2040	0	0

Q. What conclusions did you reach after analyzing these incremental capacity additions?

A. The incremental capacity additions resulted in smaller amounts of excess capacity, and associated revenues that must be recovered from ratepayers, both for the Rochester area and the whole MERC-NNG system. DOC Ex. ____at AJH-17 and AJH-18 (Heinen Direct). However, it is important to note that these incremental alternatives were only viable under lower growth scenarios. If growth in the Rochester Area is closer to the Company's forecast, if overall system peak demand grows at MERC's forecasted rate, if increased natural gas is needed by RPU or any other electric utility, or if the base peak demand in the Company's demand entitlement filing was more representative of peak demand, then the Company will be required to purchase additional capacity and, likely, invest in additional upgrades to serve customers in the Rochester Area.

Q. What were the potential costs of additional upgrades?

A. As noted in MERC's supplemental response to DOC IR No. 37, the total costs associated with an incremental approach to adding capacity , or future capacity upgrades, will likely result in higher total costs to ratepayers than the project as proposed. In addition, the Company noted that limiting expansion capacity to 30,000 Dkt/day instead of the proposed 45,000 Dkt/day resulted in a Net Present Value $1 million higher than the costs of the proposed project. DOC Ex. ____at AJH-19 (Heinen Direct). Given this analysis by the Company, it is reasonable to assume that a future upgrade to serve Rochester area customers will result in additional, significant costs to MERC ratepayers.

Q. Do you consider the excess capacity costs associated with the various scenarios above significant or unreasonable?

A. Although the excess capacity costs appear large, especially the approximately $65 million amount over the 22 year period associated with my preferred or base growth scenario, it is important to put these costs into the context of annual demand and commodity costs. On an annual basis, MERC purchases approximately $24 million of demand and approximately $120 million commodity costs, while the average amount of excess capacity may cost approximately $3 million, which means that excess capacity costs may approach 2.5 percent of total PGA costs incurred, based on current prices, for the MERC-NNG PGA system.[4] For additional perspective, MERC-NNG ratepayers have been assessed the Bison Pipeline contract since November 2010, which is recovered through the commodity portion of the PGA and has only been used at levels far below the full contracted capacity to deliver supplies to MERC ratepayers. DOC Ex. ____at AJH-20 (Heinen Direct). In the Company's Response to DOC IR No. 36, MERC stated that the average costs of the Bison Contract for Residential customers is $38.09 per year, while total capacity costs for the Rochester project will reach $32.16 per year for Residential customers. DOC Ex. ____at AJH-21 (Heinen Direct). The excess capacity costs for this project are embedded in the $32.16 figure, so, for comparative purposes, the excess costs of the not fully used Bison Contract, which ratepayers have been assessed for several years, are likely greater than the potential excess capacity costs associated with the Rochester project.

Q. Based on your reserve margin analysis and analysis of incremental capacity alternatives, what were your final conclusions regarding need?

A. I concluded that the size of MERC's proposed Project was reasonable. Although smaller alternatives may be able to meet need in the Rochester Area, this outcome would only be possible if growth in the Rochester Area, and on the MERC system as a whole, remain relatively constant despite known upward pressure on throughput such as the DMC. In the event that growth increases, there is tangible risk that

[4] These cost figures are taken from the Company's 2015 Annual Fuel Report for its NNG PGA filed in Docket No. G011/AA-15-803.

ratepayers would be required to invest in significant future upgrades that may have similar, or greater, costs to the proposed project. Any excess costs associated with the project as proposed by MERC were relatively small on an annual basis and were comparable to insurance against the potential costs of future system upgrades. I discuss in greater detail in Section VII below methods through which MERC may be able to mitigate the costs of excess capacity going forward.

VI. PROJECT ELIGIBILITY FOR RIDER RECOVERY

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

A. In this section, I address whether the Company's proposed project meets the requirements of the NGEP Statute (Minnesota Statute 216B.1638) and if the costs associated with it are eligible for recovery through the rider. As detailed in Section V above, there is need for the proposed project to serve the Rochester area; however, it is necessary to fully analyze whether the circumstances in the Rochester area match the requirements set forth in Minnesota Statutes for rider recovery.

Q. Did MERC provide testimony supporting its conclusion that this project is eligible for rider recovery?

A. Yes. The Company provided extensive testimony supporting the project's eligibility for rider recovery in its initial filing and Direct Testimony. MERC Ex. ____at 36-38 (Initial Filing) and MERC Ex. ____at 17-26 (Lee Direct).

Q. What is the relevant part of Minnesota Statute that speaks to whether a project is eligible for rider recovery?

A. For ease of reference, I have included the full language of the NGEP Statute (Minnesota Statute section 216B.1638) with this testimony. DOC Ex. ____at AJH-22 (Heinen Direct). The relevant portion of Minnesota Statute section 216B.1638 is subdivision 3, which states as follows:

> Subd. 3. **Review; approval.**
> (a) The commission shall allow for comment on the petition.
> (b) The commission shall approve a public utility's petition for a rider to recover the costs of a natural gas extension project if it determines that:
> (1) the project is designed to extend natural gas service to an unserved or inadequately served area; and
> (2) project costs are reasonable and prudently incurred.
> (c) the commission must not approve a rider under this section that allows a utility to recover more than 33 percent of the costs of a natural gas extension project.
> (d) the revenue deficiency from a natural gas extension project recoverable through a rider under this section must include the currently authorized rate of return, incremental income taxes, incremental property taxes, incremental deprecation expenses, and any incremental operation and maintenance costs.

Q. Based on your review, does the project extend natural gas service to an unserved or inadequately served area?

A. Yes. I reviewed the Company's load data for Rochester, and the TBSs in the surrounding area, and confirmed that firm usage is at, or above, currently deliverable entitlement levels. DOC Ex. ____ AJH-7 (Heinen Direct). In addition, given expected growth, even at a baseline level, it is unlikely that MERC will be able to adequately serve existing, or expected, end-use customers on a going-forward basis.

Q. Do you believe that the proposed project costs are reasonable and prudently incurred?

A. Whether or not individual costs are reasonable or prudently incurred cannot be fully determined until actual costs occur. The costs provided in this record were estimates and it will not be until a future rider filing or rate case when actual costs can be reviewed to determine final reasonableness. The cost estimates provided by the Company were used as a guide to determine reasonableness and prudency in future regulatory filings.

Q. Did the Company provide an estimate of total project costs it anticipates being eligible for rider recovery?

A. Yes. In its Direct Testimony, the Company estimated the costs of its upgrades at approximately $5.6 million for Phase I, which involved improvements to MERC's delivery system in the Rochester Area and has already been installed, and upgrade costs of approximately $44 million for Phase II, which involves reconstruction of the TBSs that serve Rochester and construction of new transmission lines to deliver gas to Rochester. MERC Ex. ____at 15-16 (Lee Direct).

Q. How did these costs differ from the capacity costs you discussed in Section V above?

A. The proposed costs that are potentially eligible for rider recovery relate to MERC-owned upgrades in the Rochester Area necessary to serve its customers. These costs will be recovered either through the rider or via the Company's base rates and be charged to all customers. The capacity costs discussed in Section V above related to the recovery of costs associated with NNG's construction costs that it will incur to facilitate the expansion of available capacity to the Rochester Area. These NNG related costs will be recovered through the monthly PGA.

Q. Does the Department have a general goal or policy as it relates to cost caps for large utility project?

A. Yes. The Department has maintained that reasonable cost estimates, and fulfilling these costs estimates, are necessary so that ratepayers are not liable for unreasonable costs or cost overruns that have no limit. Generally speaking, the Department has typically addressed concerns regarding costs caps in the rider filing or general rate case proceeding in which cost recovery from retail ratepayers is first requested. Thus, there will be subsequent cost recovery proceedings regarding MERC's various expenditures during a given year or period between regulatory filings. However, providing some clarity on expected costs at this point is important and is consistent with the Commission's approach regarding cost recovery in past Certificate of Need (CN) proceedings which are, in many respects, similar to the Company's current filing for the proposed project. In these past rulings, the Commission has limited recovery in riders only to the amount of costs that the utility proposed in its petition. Further, the utility would have the burden of proof to show that any costs above the approved level are prudent and why it would be reasonable to recover such costs from ratepayers.

Q. Do you believe it is important for the Commission to hold utilities accountable for large project costs?

A. Yes. Utility cost estimates are used extensively throughout the regulatory process and are relied upon by the Commission, particularly when considering alternatives to a proposed project. Further, approval of projects, and their subsequent cost recovery mechanism, should not constitute a blank check for cost recovery in the rider to the extent that actual costs are greater than the estimated costs relied upon in regulatory proceedings. Absent cost recovery caps tied to the evidentiary record in which the project was selected and approved, utilities have little incentive to expend the effort needed to accurately report project costs in regulatory proceedings, nor to ensure that the actual costs are as reasonable as possible.

Q. How does the Commission hold Minnesota rate-regulated utilities accountable for their project cost estimates in similar proceedings?

A. The transmission cost recovery (TCR) riders for Minnesota electric utilities illustrate how the Commission holds utilities accountable for cost estimates. In these riders, the Commission holds utilities subject to their jurisdiction accountable for their transmission CN cost estimates by capping in the utilities' riders the amount approved for recovery from ratepayers through the TCR. Utilities are allowed to request recovery of cost overruns in subsequent rate cases in the same way that they always have been able to do, but cost overruns are typically not allowed to be recovered in the extraordinary riders.

Q. Do you have examples of such decisions to limit recovery of cost overruns in riders?

A. Yes, there are many. For example, in Xcel Energy's TCR Rider filing in Docket No. E002/M-09-1048, the Commission decided the following regarding Xcel's recovery of transmission project costs on a going-forward basis in its April 7, 2010 Order in the Xcel Energy docket:

> …the Commission finds that TCR project cost recovery through the rider should be limited to the amount of the initial cost estimates at the time the projects are approved as eligible projects, with the opportunity for [Xcel Energy] to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought for Commission review only if unforeseen or extraordinary circumstances arise on a project.

The Commission also applied this same approach to Otter Tail Power, in Otter Tail Power's 2013 Transmission Cost Recovery Rider (Docket No. E015/M-13-103). The Commission stated in its March 10, 2014 Order that in the Otter Tail docket:

> Accordingly, the Commission continues to believe that project costs included in the TCR rider should be capped at certificate of need levels, and concurs with the Department that the appropriate cap for the Bemidji project is $74 million. The TCR rider mechanism gives Otter Tail the extraordinary ability to charge its ratepayers for facilities prior to the ordinary timing (the first rate case after the project goes into service) and without undergoing the full scrutiny of a rate case. Holding [Otter Tail] to its initial estimate is an important tool to enforce fiscal discipline.
>
> Further, imposition of a cap protects the integrity of the certificate of need process, in which it is critical that the cost estimates for the alternatives being compared are as reliable as possible. And, capping costs at the certificate of need levels is consistent with the Commission's actions in similar cases involving other utilities' riders.
>
> [Otter Tail] is recovering the cost of these transmission facilities through a rider, a unique regulatory tool essentially designed to enable utilities to begin recovering the prudent and reasonable costs of critically needed capital investments between rate cases. The

> rate case remains the primary vehicle for determining prudence and reasonableness.
>
> In the absence of a rate case, the best available proxy for determining prudence and reasonableness is the cost determination made on the record of a certificate of need or cost recovery eligibility proceeding. Here, the relevant proceeding is a certificate of need case. Otter Tail should continue recovering the costs it sponsored in its certificate of need case unless and until it demonstrates in a rate case that higher costs are prudent and reasonable. (footnotes omitted)

Q. What do you recommend regarding potential cost caps for this project?

A. I recommend that the Commission find that the appropriate cap for this project is $44,006,607, as detailed in its Direct Testimony. MERC Ex. ____at 16, Table 1 (Lee Direct). I do note, however, that MERC included a $7,341,321 contingency factor in its costs estimates. MERC Ex. ____at Attachment D (Initial Filing). I am unclear if this contingency factor is reasonable or comparable to similar project; and, for this reason, I recommend that the Company address this issue in its Rebuttal Testimony. In the event that costs are greater than this cap, it is the Company's burden to show that these additional costs are reasonable.

Q. Does your recommendation mean that MERC has "carte blanche" to recover any, and all, costs up to the cap level?

A. No. MERC continues to bear the burden of proof in future rider filings and general rate case proceedings to show that individual expenditures are just and reasonable. For example, it is possible that MERC has included, or intends to include, certain costs in the rider that should not be included in the rider. In the event that this occurs, the Company would not be able to recover up to the cap level because certain costs were deemed unreasonable.

Q. In terms of the amount of costs from the project, did MERC propose to recover more than 33 percent of these costs through the rider?

A. No. In accordance with the NGEP Statute, MERC did not propose to recover greater than 33 percent of project costs through the rider. MERC Ex. ____at 17 (Lee Direct).

Q. Did MERC provide discussion in this record regarding its revenue deficiency associated with the proposed project?

A. Yes. MERC provided discussion and illustrative numbers in its initial filing. MERC Ex. ____at 29-34 (Lee Direct).

Q. Does this filing represent the last time that parties, or the Commission, can raise questions regarding the reasonableness of certain costs?

A. No, it does not. The Commission will have the opportunity to review costs in future rider reviews and in subsequent general rate cases. In addition, the Commission's February 8, 2016 *Order* stated that the Commission will defer any decision on the accuracy of MERC's revenue-deficiency calculation until the Company seeks approval of an NGEP rider to recover that revenue deficiency. DOC Ex. ____at AJH-2 (Heinen Direct).

Q. The Commission will defer judgment on the reasonableness of the revenue deficiency until a later filing, but did the Company include any items, or categories, in its rider recovery examples that may be questionable?

A. Based on a review of Attachment D to the initial filing and Ms. Lee's Direct Testimony, it was unclear if MERC intended to include only incremental costs in its rider recovery proposal. MERC Ex. ____at Attachment D (Initial Filing) and MERC Ex. ____ at 18 (Lee Direct). In particular, the Company included line items for Operations and Maintenance (O&M) expenses, which can include total costs if not properly accounted for. The NGEP Statute is clear that incremental costs associated directly with the project are the only amount eligible for rider recovery. MERC is at risk of cost disallowance if it includes unapproved costs in its rider recovery proposal. In addition, I reiterate that certain costs, even if they are incremental in nature, that were incurred prior to the implementation of the NGEP Statute (*e.g.,* 2014 costs) should not be included in the rider and the Department is likely to recommend that these costs be disallowed in future regulatory filings.

Q. What are your conclusions regarding the eligibility of MERC's proposed project for rider recovery?

A. Based on my review, Rochester and the surrounding area meet the definition of an "unserved or inadequately served area" in the NGEP Statute. The reasonableness or prudency of any costs incurred will be reviewed in future rider or rate case filings; however, to the extent that these costs are found reasonable, it appears that they would be eligible for rider recovery. The Department will fully review costs in future filings and recommends that the Commission hold MERC to its current total cost estimate as a guide, or soft cap as explained above, to reasonable costs for the proposed project.

VII. MITIGATION OF CAPACITY COSTS

Q. In Section V you have extensive discussion regarding excess capacity costs associated with the Rochester project. Under MERC's proposal, who would be responsible for these costs?

A. MERC's proposal would recover these costs from MERC-NNG ratepayers through the monthly PGA. If these capacity costs were flowed solely through the demand portion of the PGA, then the Company's firm ratepayers will be responsible for the entire amount of the capacity costs. If these capacity costs were instead flowed through the commodity portion of the monthly PGA, then all of the Company's firm and interruptible customers would be responsible for capacity costs, including excess capacity costs.

Q. Returning to the topic of excess capacity costs, do you believe that the expected excess capacity costs for the Company's project were significant?

A. As noted in Section V above, I do not believe the excess capacity costs are significant when compared to annual commodity costs but these costs should not be ignored by the Company. These costs will be recovered from MERC ratepayers and it is important that the Company take whatever steps are necessary to lower costs if reasonable means exist to do so.

Q. What means, if any, does MERC have to mitigate excess capacity costs?

A. The most likely means of mitigating cost is capacity release. The Company provided a discussion of capacity release in its response to DOC discovery. DOC Ex. ____ at AJH-23 (Heinen Direct). Capacity release is the act of placing unneeded capacity on the open market for other parties to purchase to satisfy their natural gas needs. In general, capacity release occurs on a short-term basis.

Q. Did you request any additional information regarding capacity release?

A. Yes. In the Company's Response to DOC IR No. 26, MERC provided detailed information regarding its historical capacity releases since January 2007. DOC Ex. ____ AJH-23 (Heinen Direct). These data show that, on average, MERC has received approximately $625,000 in capacity release credits each year since 2007.

Q. Does capacity release provide significant value to ratepayer?

A. Since capacity release is generally on a short-term, as needed basis, the revenue associated with these releases is typically small compared to the original purchase price of the capacity. Granted, there is some relief to ratepayers but it should not be considered a significant tool to mitigate costs.

Q. Do longer-term capacity release agreements exist?

A. Yes. In my experience, I have seen other Minnesota utilities that have engaged in longer term capacity release contracts. These are generally less flexible because a given amount of capacity is released for a longer period of time (*e.g.,* two years), and it typically is non-recallable, but the revenues received from the agreement are much greater than standard capacity release. For MERC, since there is a relatively large amount of excess capacity for an extended period of time, it is possible that longer-term capacity release agreements may be beneficial to ratepayers.

Q. Did you request that MERC provide analysis on this topic?

A. Yes. In its Response to DOC IR No. 26, MERC stated that it will consider longer term capacity release agreements on a case-by-case basis. DOC Ex. ____ AJH-23 (Heinen Direct).

Q. Are there any other ways MERC can deal with this excess capacity and associated costs?

A. Yes. Although the Company is limited to 20 percent deliverability of the total Rochester Area capacity without penalty, MERC stated in its Response to DOC IR No. 23 that it can move additional capacity but at the maximum rate. DOC Ex. ____ AJH-26 (Heinen Direct). The maximum rate is significantly higher than the negotiated rate; however, it is possible that paying the maximum rate for any volumes above 20 percent may be cheaper than procuring additional entitlements to serve need in other parts of the MERC system. At a time when additional capacity is needed in other parts of MERC's system, I would anticipate that the Department will revisit this issue to determine whether MERC ratepayers received the lowest priced entitlements possible.

Q. Do you have any additional discussion on this topic?

A. No, I do not.

VIII. RATE RECOVERY

Q. Please explain the purpose of this section of your testimony.

A. In its February 8, 2016 *Order*, the Commission requested that the parties analyze whether recovery of the Rochester Project from all MERC ratepayers is reasonable and, if so, on what basis. Further, if it is found that recovery from all ratepayers is unreasonable, then what other allocation method would be more reasonable. This section addresses this request by the Commission in part. Ms. Peirce addresses the issue of apportioning the non-PGA revenue requirements to ratepayers in Rochester and the rest of MERC's system; I address recovery of costs in the PGA.

Q. You mentioned in Section III above that there is a different type of cost to consider in this proceeding than in a demand entitlement proceeding. Please explain.

A. I noted above that the Project deals with costs of expanding the capacity of NNG's system. Such costs need to be considered carefully to avoid unintended consequences.

Q. Why is it important to consider the incremental costs of expanding NNG's capacity?

A. These costs are unusual and significant, so it is important to ensure that rates appropriately reflect costs. Cost-causation is an important consideration not just for fairness purposes, but also to avoid creating an inappropriate incentive for some of MERC's large customers that would unduly and inappropriately harm other MERC customers. Since the costs of expanding NNG's capacity will be charged to MERC, and since such capacity will be used to serve MERC's sales customers *and* its transportation customers, it is important to ensure that costs of expanding NNG's capacity are appropriately charged to both sales and transportation customers, as required by the NGEP Statute. Further, as discussed below, all Rochester ratepayers are expected to benefit from the Project, the costs need to be charged to all customers – firm and interruptible, sales and transportation.

Q. Why should costs of expanding NNG's capacity be charged to all of MERC's customers?

A. This Project is being built to increase the capacity on NNG's system for natural gas to be delivered, regardless of the supplier (MERC or a third party). Thus, both sales and transportation customers need to pay their fair share, as suggested by the NGEP Statute. Further, expanding the capacity of NNG's system makes it less likely, all else equal, that interruptible customers will be interrupted. Because expansion of NNG's capacity affects all of MERC's ratepayers, both firm and interruptible customers should pay their fair share.

Moreover, charging only sales customers for the costs of the Project would give an incentive to sales customers to switch to transportation service solely to avoid paying for costs to expand the capacity to deliver natural gas to the Rochester area. Firm customers similarly would have an inappropriate incentive to switch to interruptible service and unduly benefit from avoiding costs of a system that is being built to serve them, correspondingly harming other ratepayers.

IX. OTHER FUNDING POTENTIALLY AVAILABLE FOR THIS PROJECT

Q. Please explain the purpose of this section.

A. In its February 8, 2016 *Order*, the Commission requested that parties investigate other funding sources that are available to MERC in regards to the Rochester project. This request is likely the result of the proposed DMC in Rochester and the associated State Infrastructure Aid (SIA) program authorized by Minnesota Statute section 469.47. These state funds are available for approved public infrastructure once private investment in the DMC area reaches a set threshold. For ease of reference, I have included the entirety of the DMC statutes as an attachment to this testimony. DOC Ex. _____ AJH-28 (Heinen Direct).

Q. What is the Destination Medical Center?

A. The Destination Medical Center, or DMC, is a long-term vision and development plan by the Mayo Clinic and other parties in the Rochester Area to grow the area and make it a leading center for medical treatment and research. The DMC Statutes (Minnesota Statutes sections 469.40 through 469.47) were created to aid in the implementation of the DMC and create various state and local funding streams to facilitate this implementation.

Q. What institutions or funding streams were authorized by the DMC Statutes?

A. First, the DMC Statutes created the Destination Medical Center Corporation (DMCC) whose mission is to prepare and implement the development plan for the DMC. The DMCC is also charged with approval of projects before they are forwarded to the City of Rochester for final approval. Second, the DMC Statutes authorized the creation of a development plan outlining the various goals and planned projects for the DMC. Third, the DMC Statutes authorized the creation of various state and local funding streams for implementation of the DMC. These funding streams included city and county taxes and a State Infrastructure Aid program. The state aid is available in different sources for public infrastructure and transit once private investment in the DMC has reached a defined threshold.

Q. Is the development plan referenced above available to the public?

A. Yes. A draft of the DMC development plan is available on the DMC website.[5]

Q. Have you had an opportunity to review the DMC development plan?

A. Yes. I have reviewed the entirety of the DMC development plan.

Q. How does the DMC, the DMC development plan, and the DMC Statutes as a whole relate to MERC's Rochester project?

A. First, the Rochester project relates to the DMC because implementation of the DMC, in my opinion, is extremely difficult if not impossible, if MERC does not make the upgrades associated with the proposed project. Since the Rochester area is capacity constrained in terms of natural gas, the planned construction and expansions in the DMC development plan will not have access to sufficient natural gas supplies. This would likely complicate development and require incremental growth to rely fully on the local electric utility to supply various needs such as space heating.

Second, the Rochester project clearly meets the standard definition of a public infrastructure project. Public infrastructure is defined as infrastructure that is

[5] Given the voluminous nature of this plan, I have not attached it to my testimony, but it can be found at the following link: http://dmc.mn/press-materials/#devPlan.

owned by the public or for public use, of which, utility and energy infrastructure is generally included. In addition, Minnesota Statute section 469.40 includes a definition of “public infrastructure project” which is, in many ways, a starting point for what projects may be eligible for funds through SIA. The definition of public infrastructure for DMC purposes is as follows:

> **Subd. 11.Public infrastructure project.**
>
> (a) "Public infrastructure project" means a project financed in part or in whole with public money in order to support the medical business entity's development plans, as identified in the DMCC development plan. A public infrastructure project may:
>
> (1) acquire real property and other assets associated with the real property;
>
> (2) demolish, repair, or rehabilitate buildings;
>
> (3) remediate land and buildings as required to prepare the property for acquisition or development;
>
> **(4) install, construct, or reconstruct elements of public infrastructure required to support the overall development of the destination medical center development district including, but not limited to, streets, roadways, utilities systems and related facilities, utility relocations and replacements, network and communication systems, streetscape improvements, drainage systems, sewer and water systems, subgrade structures and associated improvements, landscaping, façade construction and restoration, wayfinding and signage, and other components of community infrastructure**; (bold added for emphasis)
>
> (5) acquire, construct or reconstruct, and equip parking facilities and other facilities to encourage intermodal transportation and public transit;
>
> (6) install, construct or reconstruct, furnish, and equip parks, cultural, and recreational facilities, facilities to promote tourism and hospitality, conferencing and conventions,

and broadcast and related multimedia infrastructure;

(7) make related site improvements including, without limitation, excavation, earth retention, soil stabilization and correction, and site improvements to support the destination medical center development district;

(8) prepare land for private development and to sell or lease land;

(9) provide costs of relocation benefits to occupants of acquired properties; and

(10) construct and equip all or a portion of one or more suitable structures on land owned by the city for sale or lease to private development; provided, however, that the portion of any structure directly financed by the city as a public infrastructure project must not be sold or leased to a medical business entity.

(b) A public infrastructure project is not a business subsidy under section 116J.993.

(c) Public infrastructure project includes the planning, preparation, and modification of the development plan under section 469.43. The cost of that planning, preparation, and any modification is a capital cost of the public infrastructure project.

The current capacity constraint in the Rochester Area clearly shows that MERC's natural gas infrastructure is needed to facilitate growth of the DMC. The bolded section above also shows that the type of utility work MERC envisions is classified by Statute as public infrastructure.

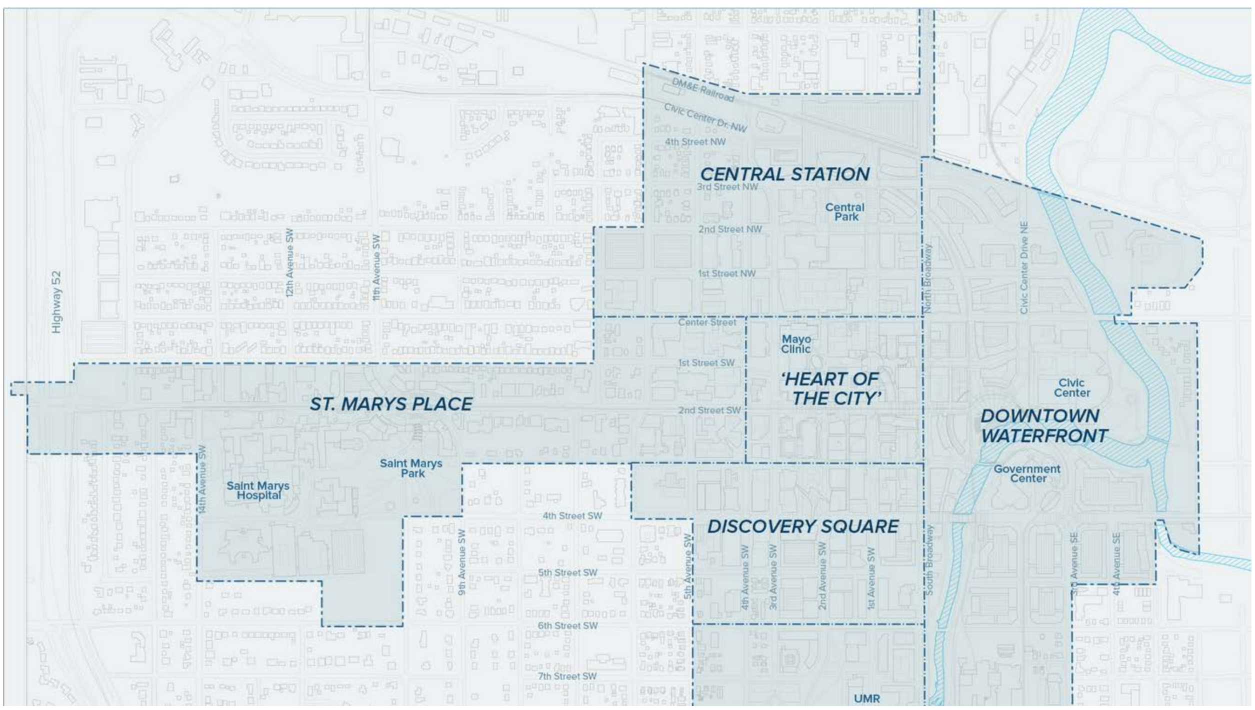
Q. Do Minnesota Statutes provide any additional guidance on how an infrastructure project may be eligible for SIA funding?

A. Yes. The DMC Statutes also make reference to a DMC development district. Minnesota Statute section 469.40, Subd. 5 defines the development district as: "a geographic area in the city identified in the DMCC development plan in which public infrastructure projects are implemented."

Q. Does the current DMCC development plan define the boundaries of the development district?

A. Yes. The map below, taken from the development plan, outlines the general location of the development district.

Map 1: Current Destination Medical Center Boundaries and Sub-districts



The district, as currently defined, is generally located in the downtown Rochester Area in, and around, the Mayo Clinic Campus.

Q. Is the DMCC development plan, and corresponding development district, static or can it be changed?

A. The development plan and development district boundaries can be modified. Minnesota Statute section 469.43, Subds. 4 and 5 allow for modification of the development plan and, conceivably, the development district. These subdivisions state the following:

> **Subd. 4.Modification of development plan.**
>
> The corporation may modify the development plan at any time. The corporation must update the development plan not less than every five years. A modification or update under this subdivision must be adopted by the corporation upon the notice and after the public hearing and findings required for the original adoption of the development plan, including approval by the city.
>
> **Subd. 5.Medical center development districts; creation; notice; findings.**
>
> As part of the development plan, the corporation may create and define the boundaries of medical center development districts and subdistricts at any place or places within the city. Projects may be undertaken within defined medical center development districts consistent with the development plan.

Q. Has MERC applied for SIA funds to help with the construction of its project?

A. Yes. The Company included its application for funding in the Direct Testimony of Ms. Lee. MERC Ex. ____ ASL-2 and ASL-3 (Lee Direct). MERC has requested $5 million to aid in the construction of the Rochester project.

Q. Based on your review of the draft DMC development plan and the DMC Statutes, do you believe the Company's project can be considered a public infrastructure project in terms of eligibility for SIA?

A. Although the project clearly meets the definition of a public infrastructure project, in the regular sense, and will help facilitate the implementation of the DMC by relieving natural gas constraints in the Rochester Area, it does not appear that MERC's project meets the definition in the DMC Statutes. The primary reason is that the planned work by the Company does not occur within the DMC development district, which was confirmed in MERC's Response to DOC IR No. 28. DOC Ex. ____ AJH-29 (Heinen Direct). Without a modification to the DMC development boundaries, it is unclear how successful MERC's application, as provided in Ms. Lee's Direct Testimony, for SIA funding will be or whether it is possible given how the DMC Statutes are written.

Q. Do you believe the Company may have potential access to SIA funding in the future?

A. Yes. To the extent the private spending threshold is met, I do believe the Company may have access to SIA funding for certain future work. Although the DMCC and City of Rochester have final say on what public infrastructure projects are eligible for funds, if MERC undertakes projects within the DMC development area, I see no reason why the Company would not have a legitimate reason to access SIA funds. For example, if MERC is required to upgrade its infrastructure or install additional equipment to serve a new customer within in the development area, especially if it involves replacing equipment that still have remaining life, it would be reasonable and prudent to petition the DMCC for SIA funds. I believe it would be unreasonable to require MERC ratepayers to pay for these types of costs when other means of recovery exist.

Q. What are you recommendations and conclusions regarding funding from other sources?

A. Based on my analysis of the Company's project and the DMC Statutes, I conclude that it is unlikely that MERC's project will qualify for state aid since the project will occur outside of the DMCC development district. To the extent that future work by the Company occurs within the development district, I recommend that MERC petition the DMCC for SIA funds since utility infrastructure is generally considered public infrastructure and it is meant to promote implementation of the DMC. I also recommend that the Company include a discussion and supporting data, as part of its annual rider filing, detailing any, and all, utility work done throughout the previous year within the development district, the number of applications made to the DMCC, and the amount of state aid received.

X. SUMMARY, RECOMMENDATIONS, AND CONCLUSIONS

Q. Please summarize your conclusions regarding the Company's proposed need for this project.

A. Based on my review of the Company proposal and supporting analysis, I identified potential issues with MERC's estimate of customer count growth which is a driving factor in the Company's need forecast. In response, I conducted an independent analysis of MERC's need proposal. Based on this analysis, I conclude that the Rochester Area is constrained and that the size of the project, as proposed by the Company, is reasonable and represents the best means of meeting current and expected need in the Rochester Area. Although excess capacity exists, I do not believe these costs are significant and I provided discussion of methods available to mitigate these costs.

Q. Please summarize your conclusions and recommendations regarding the eligibility of this project for NGEP rider recovery.

A. I reviewed the Company's proposed project and compared it to the requirements set forth in the NGEP Statute. Based on my analysis, I concluded that the Company's proposed project is eligible for rider recovery under Minnesota Statute 216B.1638, the NGEP Statute. In addition, I also recommend that the Commission hold MERC to its cost estimate provided in this testimony. Specifically, I recommend that the Commission find that the appropriate cost cap for this project is $44,006,607. I also noted that the Department will fully review costs in future regulatory filings.

Q. Please summarize your conclusions and recommendations regarding methods to mitigate capacity costs.

A. I concluded that the excess capacity costs associated with this project are not significant; however, these costs are noticeable and MERC should take steps to mitigate cost increases to its ratepayers where possible. I noted that capacity release is a method available to MERC; however, this is generally a short-term solution and is not typically of high value to ratepayers. I did, however, recommend that MERC explore options for long-term capacity release, which, when available, return more revenues to ratepayers. I also concluded that the Company may be able to mitigate capacity costs by actively attempting to move interruptible customers to firm service, who will benefit from firm service, and to also be proactive in finding potential purchasers of firm capacity from the electric industry as natural gas becomes a more attractive generation source. Finally, I concluded that the Company may be able to mitigate future prices by using available excess capacity to avoid purchasing other, more expensive, capacity to serve other parts of the MERC-NNG PGA system.

Q. Please summarize your conclusions regarding ratepayer recovery.

A. I noted, first, that Ms. Peirce addresses the issue of recovering costs from ratepayers in Rochester and elsewhere on MERC's system, along with the method of recovery. I also noted that this Project is being built to increase the capacity on NNG's system for natural gas to be delivered, regardless of the supplier (MERC or a third party). Thus, I recommended that both sales and transportation customers pay for the Project, as suggested by the NGEP Statute. Further, since expanding the capacity of NNG's system makes it less likely, all else equal, that interruptible customers will be interrupted, I recommended that the costs of the Project be recovered from both firm and interruptible customers.

Q. Please summarize your conclusions and recommendations regarding funding from other sources.

A. In its February 8, 2016 *Order*, the Commission requested that parties analyze the availability of other funding sources to offset the cost of the project. Given this directive, I analyzed the Destination Medical Center Statutes to determine whether MERC's project is available for State Infrastructure Aid funding which was authorized with in these Statutes. Based on my analysis, I concluded that the Company's project can be considered public infrastructure in the general sense; however, since the work being done by MERC does not occur with in the development district required in the DMC Statutes, it is unlikely that the proposed project is considered a public infrastructure project for SIA funding purposes. As such, I concluded that it is unlikely that MERC is eligible for public funding at this time. However, I did conclude that to the extent the Company undertakes work within the district in the future, there does not appear to be a reason to prevent MERC from seeking funding. I recommended that MERC petition the DMCC for SIA funds when it conducts work inside the DMCC district. Utility infrastructure is generally considered public infrastructure and work done within the district will clearly be to the benefit of implanting the DMCC development plan. I also recommend that the Company include a discussion and supporting data, as part of its annual rider filing, detailing any, and all, utility work done throughout the previous year within the development district, the number of applications made to the DMCC, and the amount of state aid received.

Q. Does this conclude your Direct Testimony?

A. Yes.

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

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St Paul, MN 55101-2147

IN THE MATTER OF THE APPLICATION OF MINNESOTA ENERGY RESOURCES CORPORATION FOR AUTHORITY OF RIDER RECOVERY FOR THE ROCHESTER NATURAL GAS EXTENSION FOR NATURAL GAS SERVICE IN MINNESOTA

MPUC Docket No. G011/M-15-895
OAH Docket No. 68-2500-3319

DIRECT ATTACHMENTS OF ADAM J. HEINEN (PART I – AJH-1 TO AJH-5)

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

FINANCIAL ISSUES

JULY 1, 2016

Summary of Attachments

Attachment	Description	Pages
AJH-1	Resume and Qualifications	3
AJH-2	February 8, 2016 Commission *Order*	8
AJH-3	October 12, 2015 City of Rochester Proclamation	1
AJH-4	Rochester Public Utilities 2015 Infrastructure Study	68
AJH-5	MERC Response to DOC Information Request No. 48	25
AJH-6	Regression results from MERC's 2015 Demand Entitlement Filings	2
AJH-7	MERC Response to DOC Information Request No. 16	4
AJH-8	MERC Response to DOC Information Request No. 18	4
AJH-9	Calculation of MERC's Average Customer Count Growth	8
AJH-10	2010 United States Census Data and Household and Population Data from the Minnesota State Demographer	14
AJH-11	Calculation of Olmsted County Household Growth Rates	1
AJH-12	Design Day Data from the 2015 and 2012 Demand Entitlement Filings	2
AJH-13	Regression Results from DOC Peak Day Forecast	1
AJH-14	DOC Customer Count Forecast	5
AJH-15	DOC Alternative Need Analysis	14
AJH-16	DOC Preferred Reserve Margin and Capacity Cost Analysis	3
AJH-17	DOC Reserve Margin Analysis: 25,000 Dkt/day of Added Capacity	3
AJH-18	DOC Reserve Margin Analysis: 35,000 Dkt/day of Added Capacity	3
AJH-19	MERC Response to DOC Information Request No. 37	13
AJH-20	MERC Informal Discovery Response	1
AJH-21	MERC Response to DOC Information Request No. 36	

Attachment	Description	Pages
AJH-22	Minnesota Statute 216B.1638	2
AJH-23	MERC Response to DOC Information Request No. 26	2
AJH-24	MERC Response to DOC Information Request No. 32	2
AJH-25	February 24, 2016 *Rochester Post-Bulletin* Article Regarding RPU's Westside Energy Station	3
AJH-26	MERC Response to DOC Information Request No. 23	2
AJH-27	Cost Estimates from Xcel Energy's GUIC Rider Filing	1
AJH-28	Destination Medical Center Statutes (Minnesota Statutes 469.40-469.47)	21
AJH-29	MERC Response to DOC Information Request No. 28	2

Adam J. Heinen

85 7th Place East, Suite 500 – Saint Paul, MN, 55101
(651)-539-1825
adam.heinen@state.mn.us

TESTIMONY:

Rate Design, PGA Consolidation, Tariff Review, Extension Policy Review: Great Plains Natural Gas Company, Docket No. G008/GR-15-879
- Direct Testimony: February 23, 2016
- Surrebuttal Testimony: April 4, 2016

Forecasting, Appropriate Weather for Rate Making: CenterPoint Energy, Docket No. G008/GR-15-424
- Direct Testimony: November 24, 2015
- Surrebuttal Testimony: January 11, 2016

Demand and Need: North Dakota Pipeline Company, Docket No. PL6668/CN-13-473
- Direct Testimony: November 19, 2014
- Rebuttal Testimony: January 6, 2015
- Surrebuttal Testimony: January 21, 2015

Demand and Need: ITC-Midwest, Docket No. ET6675/CN-12-1053
- Direct Testimony: March 28, 2014
- Surrebuttal Testimony: May 9, 2014

Forecasting, Appropriate Weather for Rate Making: CenterPoint Energy, Docket No. G008/GR-13-316
- Direct Testimony: November 26, 2013
- Surrebuttal Testimony: January 10, 2014

Forecasting: Northern States Power d/b/a Xcel Energy, Docket No. E002/GR-12-961
- Direct Testimony: February 28, 2013
- Surrebutal Testimony: April 12, 2013

Forecasting: Otter Tail Power Company, Docket No. E017/M-10-1082
- Direct Testimony: August 29, 2011

Forecasting, Purchased Gas Adjustment Consolidation, Cost of Natural Gas: Minnesota Energy Resources Corporation, Docket No. G007,011/GR-10-977
- Direct Testimony: May 3, 2011
- Surrebutal Testimony: June 20, 2011
- Additional Rebuttal Testimony: October 12, 2011

Forecasting: Otter Tail Power Company, Docket No. E017/GR-10-239
- Direct Testimony: September 15, 2010
- Surrebuttal Testimony: November 8, 2010

Case Coordinator and Test-Year Sales: Greater Minnesota Gas, Docket No. G022/GR-09-962
- Comments: April 13, 2010

Forecasting, Inflation Rates, Cost of Natural Gas: CenterPoint Energy, Docket No. G008/GR-08-1075
- Direct Testimony: June 26, 2009
- Rebuttal Testimony: July 20, 2009
- Surrebuttal Testimony: July 31, 2009

Adam J. Heinen

85 7th Place East, Suite 500 – Saint Paul, MN, 55101
(651)-539-1825
adam.heinen@state.mn.us

Forecasting: Minnesota Energy Resources Corporation, Docket No. G007,011/GR-08-835
• Direct Testimony: December 4, 2008

Forecasting: Minnesota Power Company, Docket No. E015/GR-08-415
• Direct Testimony: September 26, 2008
• Surrebuttal Testimony: November 5, 2008

Forecasting: Otter Tail Power Company, Docket No. E017/GR-07-1178
• Direct Testimony: January 31, 2008
• Surrebuttal Testimony: March 10, 2008

Demand and Need: Enbridge Pipeline, Docket No. PL9/CN-07-465
• Direct Testimony: October 5, 2007
• Rebuttal Testimony: April 25, 2008

Demand and Need: Enbridge Pipeline, Docket No. PL9/CN-07-464
• Direct Testimony: October 5, 2007
• Surrebuttal Testimony: January 4, 2008

OTHER DOCKETS:

Forecasting: Otter Tail Power Company, 2013 Integrated Resource Plan Docket No. E017/RP-13-961
• Comments Filed: May 2, 2014

Forecasting: Dairyland Power Cooperative, 2011 Integrated Resource Plan Docket No. ET3/RP-11-918
• Comments Filed: March 8, 2012

Coordinator: All Regulated Natural Gas Utilities, 2009-2010 Annual Fuel Report Docket No. G999/AA-10-885
• Comments Filed: June 15, 2011

Forecasting: Otter Tail Power Company, 2010 Integrated Resource Plan Docket No. E017/RP-10-623
• Comments Filed: May 16, 2011

Forecasting: Minnkota Power Cooperative, 2010 Integrated Resource Plan Docket No. ET6,ET6123/RP-10-782
• Comments Filed: December 29, 2010

Coordinator: All Regulated Natural Gas Utilities, 2008-2009 Annual Fuel Report Docket No. G999/AA-09-896
• Comments Filed: June 18, 2010

Forecasting: Dairyland Power Cooperative, 2008 Integrated Resource Plan Docket No. ET3/RP-08-113
• Comments Filed: March 30, 2009

Coordinator: All Regulated Natural Gas Utilities, 2007-2008 Annual Fuel Report Docket No. G999/AA-08-1011
• Comments Filed: June 15, 2009

EXPERIENCE:

Adam J. Heinen

85 7th Place East, Suite 500 – Saint Paul, MN, 55101
(651)-539-1825
adam.heinen@state.mn.us

January 2007-Present — **Public Utilities Rates Analyst; Minnesota Department of Commerce, Division of Energy Resources; St. Paul, MN**
- Sponsor and defend testimony in contested case proceedings
- File comments in cases before the Minnesota Public Utilities Commission
- Conduct analytical and policy analysis independently and in cooperative groups
- Help maintain safe and efficient natural gas and electrical service to Minnesota ratepayers

August 2005-December 2006 — **Graduate Assistant; Marquette University; Milwaukee, WI**
- Grade assignments
- Manage class rosters
- Aid in posting class materials online

Summer 2004 and 2005 — **Internship; Assistant Building Inspector; City of North Mankato; North Mankato, MN**
- Oversee Infrastructure and paving projects
- Enforce city zoning and variance ordinances

EDUCATION:

MARQUETTE UNIVERSITY, Milwaukee, WI
Master of Science Degree in Applied Economics, December 2006
GPA: 3.50/4.00

MINNESOTA STATE UNIVERSITY, Mankato, MN
Bachelor of Arts Degree in Economics, May 2005
Bachelor of Science Degree in Urban and Regional Studies, May 2005
GPA: 3.78/4.00 Economics GPA: 3.48/4.0 Urban Studies GPA: 4.0/4.0

COURSEWORK:

Graduate Level:	Applied Econometrics I and II	Advanced Macroeconomic Theory
	Advanced Microeconomic Theory and Applications	Real Estate Finance
	Standards in Labor Market Analysis	Quantitative Business Analysis
	Sports/Urban Economics	International Trade
Undergraduate Level:	Forecasting Techniques for Economics	Collective Bargaining
	Urban Analysis: Field and Research	Public Speaking
	Business Communications	Technical Communications
	Business Statistics	Senior Seminar

ACCOMPLISHMENTS:

Undergraduate: Dean's List Seven of Eight Semesters (MNSU), Graduate Magna Cum Laude

Member: Minnesota Association of Professional Employees (MAPE), Phi Kappa Phi Honor Society, Golden Key Honor Society, Students of Urban Regional Studies (President Spring 2005)

Research Projects: Thesis: Optimum Currency Area Among English Speaking Nations in Southern Africa; Tournament Effects: An Empirical Examination of NASCAR; The Effects of High School Peer Influence and Self-Esteem Characteristics on Future Success

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	Chair
Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John A. Tuma	Commissioner

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

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota

ISSUE DATE: February 8, 2016

DOCKET NO. G-011/M-15-895

DOCKET NO. G-011/GR-15-736

NOTICE OF AND ORDER FOR HEARING

PROCEDURAL HISTORY

I. Initial Filings

On October 26, 2015, Minnesota Energy Resources Corporation (MERC or the Company) filed a petition for evaluation and approval of rider recovery for its Rochester Natural Gas Extension Project under the natural gas extension project (NGEP) statute.[1]

The project is designed to expand the capacity of MERC's natural gas distribution system in and around the City of Rochester to meet anticipated demand. MERC seeks to recover a portion of the project's costs under the NGEP statute, which allows rider recovery of one third of the revenue deficiency from an eligible natural gas extension project.[2]

MERC supplemented its petition on December 7, 2015.[3]

II. Party Comments

On November 3, 2015, the Commission issued a notice soliciting comments on how MERC's petition should be handled—whether it should be referred to the Office of Administrative Hearings (OAH) for a contested-case proceeding and, if not, how the Commission should proceed.

[1] Minn. Stat. § 216B.1638 (2015).

[2] MERC's petition is the first to be filed under the NGEP statute, which was enacted in 2015.

[3] *See* MERC's Reply Procedural Comments at 6. The supplemental information concerned forecasted operating and maintenance expenses, tax-rate assumptions, sales-forecast model input data, and apportionment of responsibility for the project's revenue requirement.

By November 25, the Commission had received initial comments from the following parties:

- The Minnesota Department of Commerce, Division of Energy Resources (the Department);
- The Minnesota Office of the Attorney General – Residential Utilities and Antitrust Division (the OAG);
- Northern Natural Gas Company (NNG), an interstate natural gas transmission company that supplies natural gas to MERC; and
- The Company.

Between December 24 and January 5, the Department and the OAG filed reply comments, and MERC filed a response to the Department's reply.

The Department and MERC recommended that the Commission hold the Company's petition in abeyance and direct the parties to address the project's reasonableness in MERC's general rate case that is currently before the OAH.[4] MERC has requested recovery of some Rochester Project costs in the rate case, and the appropriate allocation of those costs among MERC's customer classes is already an issue in that case.

The OAG recommended that the Commission refer MERC's petition to the OAH for a separate contested-case proceeding, arguing that referring the Rochester petition to the rate case would not give stakeholders sufficient opportunity to thoroughly evaluate the project.

On January 14, 2016, the Commission met to consider the matter.

FINDINGS AND CONCLUSIONS

I. Background

A. The Natural Gas Extension Project Statute

The NGEP statute allows a public utility to petition the Commission, outside of a general rate case, for a rider to recover the revenue deficiency from a natural gas extension project.[5] The statute defines "natural gas extension project" as "the construction of new infrastructure or upgrades to existing natural gas facilities necessary to serve currently unserved or inadequately served areas."[6]

A petition under the NGEP statute must include the following information:

(1) a description of the natural gas extension project, including the number and location of new customers to be served and the distance over which natural gas will be distributed to serve the unserved or inadequately served area;

---

[4] *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.

[5] Minn. Stat. § 216B.1638, subd. 2.

[6] *Id.*, subd. 1(e).

(2) the project's construction schedule;

(3) the proposed project budget;

(4) the amount of any contributions in aid of construction;

(5) a description of efforts made by the public utility to offset the revenue deficiency through contributions in aid to construction;

(6) the amount of the revenue deficiency, and how recovery of the revenue deficiency will be allocated among industrial, commercial, residential, and transport customers;

(7) the proposed method to be used to recover the revenue deficiency from each customer class, such as a flat fee, a volumetric charge, or another form of recovery;

(8) the proposed termination date of the rider to recover the revenue deficiency; and

(9) a description of benefits to the public utility's existing natural gas customers that will accrue from the natural gas extension project.[7]

The Commission must approve a petition if it determines that (1) the project is designed to extend natural gas service to an unserved or inadequately served area and (2) the project costs are reasonable and prudently incurred.[8] The Commission must not approve an NGEP rider that allows a utility to recover more than 33 percent of the costs of a natural gas extension project.[9]

B. The Rochester Project

The Rochester Project will expand the capacity of MERC's natural gas distribution system in the Rochester area. The Company stated that its system is currently at capacity and must be upgraded to meet current demand and forecasted growth in customer demand over the next ten years. MERC anticipates that this growth will be driven in part by efforts to develop the Mayo Clinic as a Destination Medical Center.

MERC plans to implement the project in two phases. Phase I, which is already underway, involves modernizing, standardizing, and interconnecting portions of MERC's district regulator stations and piping within the city. MERC expects Phase I to be finished in late 2015 or early 2016 at a cost of $5.6 million. The Company is seeking recovery of this cost in its pending rate case.[10]

Phase II will involve upgrading Rochester's town-border-station system, which receives natural gas from NNG's high-pressure interstate pipeline system and transmits it at a reduced pressure for delivery to the city's low-pressure distribution system. This upgrade will allow MERC to manage an increased supply of natural gas delivered by NNG to meet customer demand. MERC plans to begin Phase II work in 2016 and complete it in 2023.

---

[7] *Id.*, subd. 2(b).

[8] *Id.*, subd. 3(b).

[9] *Id.*, subd. 3(c).

[10] Docket No. G-011/GR-15-736.

MERC estimates that Phase II construction will cost approximately $44 million. The Company has included some $640,000 in its rate case for Phase II costs expected to be incurred in 2016. After 2016, MERC plans to seek recovery of 33 percent of Phase II costs through an NGEP rider, with the balance to be recovered in future rate cases.

In addition to the above-mentioned upgrades by MERC, NNG will be increasing the capacity of its transmission system in southeastern Minnesota pursuant to a new 30-year capacity contract. The contract commits NNG to making the infrastructure upgrades necessary to provide MERC with natural gas at volumes sufficient to meet the projected growth in customer demand over the contract's term.

NNG estimates that the capital costs of expanding its interstate pipeline system in the Rochester area will be approximately $55 million, which NNG expects to recover from MERC through its contract. MERC would then seek the Commission's approval to recover the costs from ratepayers through its purchased-gas-adjustment rider.

II. Petition Completeness

The Department reviewed MERC's petition and the supplemental information the Company filed on December 7, 2015. Based on its review of MERC's filings and the NGEP statute, the Department concluded that the Company had provided the information required by the statute. The Commission concurs in the Department's analysis and will accept MERC's petition as being substantially complete.

III. Referral for Contested-Case Proceedings

Having found MERC's petition substantially complete, the Commission will refer the petition to the Office of Administrative Hearings (OAH) for contested-case proceedings. For the reasons explained below, the Commission will refer it as a standalone contested case, rather than as part of MERC's pending rate case. Finally, in the interest of efficiency, the Commission will move all Rochester Project Phase II costs and issues from the rate case to this docket.

If a proceeding involves contested material facts and there is a right to a hearing under statute or rule, or if the Commission finds that all significant issues have not been resolved to its satisfaction, the Commission must refer the matter to the OAH for contested-case proceedings.[11]

The Commission finds that it cannot satisfactorily resolve all questions regarding the Rochester Project on the basis of MERC's filings. Evaluating the reasonableness and prudence of the project will involve factual determinations, policy decisions, and the first interpretation of a new statute. The development of a comprehensive, disciplined record by an administrative law judge will greatly aid the Commission's decision-making in this matter. The Commission will therefore refer MERC's petition to the OAH.

The Commission concurs with the OAG that MERC's petition should be handled separately from the Company's pending rate case. Intervenor direct testimony in the rate case is due on March 18, 2016,[12] and inserting a new issue at this point—particularly one as complex as the Rochester Project—would

[11] Minn. R. 7829.1000.

[12] Docket No. G-011/GR-15-736, Amended First Prehearing Order at 3 (December 15, 2015).

likely impair stakeholders' ability to address it thoroughly and divert attention from other important issues in the rate case.

MERC would prefer to include the Rochester Project in the rate case because it would ensure a decision on the project's reasonableness by October 31, 2016. However, MERC stated that if the Commission does not include the Rochester Project in the rate case, the Company would prefer that the Rochester cost-allocation issues that are currently part of the rate case be addressed in the separate proceeding.

The Commission is convinced that the Rochester Project's novelty, complexity, and substantial cost require that it be addressed separately from the rate case. In the interest of efficiency, however, the Commission will move all Phase II costs and issues, including rate design, from the rate case to this docket. And, recognizing that a timely decision on MERC's petition will help ensure a reliable gas supply, the Commission will request that the administrative law judge return a recommendation, to the extent practicable, by November 30, 2016.

IV. Issues to Be Addressed

The Commission requests that the OAH include the following issues in the scope of the contested case:

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?[13]
3. What other funds may be available to cover the project costs?[14]

The Commission will defer any decision on the accuracy of MERC's revenue-deficiency calculation until the Company seeks approval of an NGEP rider to recover that revenue deficiency.

V. Procedural Outline

A. Administrative Law Judge

The administrative law judge assigned to this case is Jeanne M. Cochran. Her address and telephone number are as follows: Office of Administrative Hearings, 600 North Robert Street, Saint Paul, Minnesota 55164, (651) 361-7222.

[13] This issue bears analysis in light of the frequent practice of imposing customer-specific infrastructure costs on the customers that directly benefit from those costs—e.g., through new-area surcharges and contributions in aid of construction.

[14] One potential source of funds is state aid under Minn. Stat. §§ 469.40–.47 for infrastructure projects that support the development of the Mayo Clinic as a destination medical center.

B. Hearing Procedure

- *Controlling Statutes and Rules*

Hearings in this matter will be conducted in accordance with the Administrative Procedure Act, Minn. Stat. §§ 14.57–.62; the rules of the Office of Administrative Hearings, Minn. R. 1400.5100–.8400; and, to the extent that they are not superseded by those rules, the Commission's Rules of Practice and Procedure, Minn. R. 7829.0100–.3200.

Copies of these rules and statutes may be purchased from the Print Communications Division of the Department of Administration, 660 Olive Street, Saint Paul, Minnesota 55155, (651) 297-3000. These rules and statutes also appear on the State of Minnesota's website at www.revisor.mn.gov/pubs.

The Office of Administrative Hearings conducts contested case proceedings in accordance with the Minnesota Rules of Professional Conduct and the Professionalism Aspirations adopted by the Minnesota State Bar Association.

- *Right to Counsel and to Present Evidence*

In these proceedings, parties may be represented by counsel, may appear on their own behalf, or may be represented by another person of their choice, unless otherwise prohibited as the unauthorized practice of law. They have the right to present evidence, conduct cross-examination, and make written and oral argument. Under Minn. R. 1400.7000, they may obtain subpoenas to compel the attendance of witnesses and the production of documents.

Parties should bring to the hearing all documents, records, and witnesses necessary to support their positions.

- *Discovery and Informal Disposition*

Any questions regarding discovery under Minn. R. 1400.6700–.6800 or informal disposition under Minn. R. 1400.5900 should be directed to Robert Harding, Financial Analysis Unit Supervisor, Minnesota Public Utilities Commission, 121 7th Place East, Suite 350, Saint Paul, Minnesota 55101-2147, (651) 201-2237.

- *Protecting Not-Public Data*

State agencies are required by law to keep some data not public. Parties must advise the Administrative Law Judge if not-public data is offered into the record. They should take note that any not-public data admitted into evidence may become public unless a party objects and requests relief under Minn. Stat. § 14.60, subd. 2.

- *Accommodations for Disabilities; Interpreter Services*

At the request of any individual, this agency will make accommodations to ensure that the hearing in this case is accessible. The agency will appoint a qualified interpreter if necessary. Persons must promptly notify the Administrative Law Judge if an interpreter is needed.

- *Scheduling Issues*

The times, dates, and places of evidentiary hearings in this matter will be set by order of the Administrative Law Judge after consultation with the Commission and intervening parties. The Commission requests that the Administrative Law Judge hold public hearings in Rochester and other locations in MERC's service area.

- *Notice of Appearance*

Any party intending to appear at the hearing must file a notice of appearance (Attachment A) with the Administrative Law Judge within 20 days of the date of this *Notice of and Order for Hearing.*

- *Sanctions for Non-compliance*

Failure to appear at a prehearing conference, a settlement conference, or the hearing, or failure to comply with any order of the Administrative Law Judge, may result in facts or issues being resolved against the party who fails to appear or comply.

C. Parties and Intervention

The current parties to this case are MERC, the Department, and the OAG. Other persons wishing to become formal parties shall file petitions to intervene with the Administrative Law Judge. They shall serve copies of such petitions on all current parties and on the Commission.[15]

The Commission requests that the OAH add the City of Rochester, Mayo Clinic, and the Destination Medical Center governing board to the service list for this case and any future NGEP rider petitions to facilitate their ability to participate in developing Rochester Project issues. MERC should provide contact information, if needed.

D. Prehearing Conference

A prehearing conference will be held at a date, time, and place to be set by the Administrative Law Judge in consultation with Commission staff.

Persons participating in the prehearing conference should be prepared to discuss time frames, scheduling, discovery procedures, and similar issues. Potential parties are invited to attend the prehearing conference and to file their petitions to intervene as soon as possible.

E. Time Constraints

In light of the need to complete the Rochester Project in time to meet forecasted demand, the Commission will request that, to the extent practicable, the Administrative Law Judge return a report no later than November 30, 2016.

VI. Application of Ethics in Government Act

The lobbying provisions of the Ethics in Government Act, Minn. Stat. §§ 10A.01–.51, apply to cases involving rate setting. Persons appearing in this proceeding may be subject to registration,

---

[15] *See* Minn. R. 1400.6200.

reporting, and other requirements set forth in that Act. All persons appearing in this case are urged to refer to the Act and to contact the Campaign Finance and Public Disclosure Board, telephone number (651) 539-1180, with any questions.

VII. *Ex Parte* Communications

Restrictions on *ex parte* communications with Commissioners and reporting requirements regarding such communications with Commission staff apply to this proceeding from the date of this order. Those restrictions and reporting requirements are set forth at Minn. R. 7845.7300–.7400, which all parties are urged to consult.

ORDER

1. The Commission hereby accepts MERC's petition as being substantially complete.

2. The Commission refers MERC's petition to the Office of Administrative Hearings (OAH) as a separate, standalone contested case, moving all Rochester Project Phase II costs and issues from MERC's general rate case to this docket.

3. The Commission requests that, to the extent practicable, the Administrative Law Judge return a report no later than November 30, 2016.

4. The Commission requests that the OAH hold public hearings in Rochester and other locations in MERC's service area.

5. The Commission requests that the OAH add the City of Rochester, Mayo Clinic, and the Destination Medical Center governing board to the service list for this case and any future NGEP rider petitions to facilitate their ability to participate in developing Rochester Project issues. MERC will provide contact information, if needed.

6. This order shall become effective immediately.

BY ORDER OF THE COMMISSION

Daniel P. Wolf
Executive Secretary

This document can be made available in alternative formats (e.g., large print or audio) by calling 651.296.0406 (voice). Persons with hearing loss or speech disabilities may call us through their preferred Telecommunications Relay Service.

City of Rochester

Proclamation

WHEREAS, In order to ensure a livable planet for current and future generations, we urgently need to build societies powered by safe, affordable, and sustainable energy; and

WHEREAS, The close interconnection between our current energy system and the emerging climate crisis demonstrates that energy is not only the key problem we need to solve, it is also the solution

WHEREAS, The goal of fully transitioning the world's total energy mix toward renewable energy sources is no longer a utopian ideal – it is being achieved in a number of places around the world today. Achieving 100% renewable energy is both possible and affordable, and can be achieved with today's technologies; and

WHEREAS, The first step toward achieving 100% renewable energy is to set a formal political target. Setting an ambitious, long-term renewable energy target demonstrates political commitment, and can provide both stakeholders and the population an understanding of the long-term vision for the jurisdiction; and

THEREFORE BE IT RESOLVED, That together we will strive to achieve a goal of attaining 100% renewable energy by 2031. This goal must include:

Energy efficiency as a top priority: By developing more efficient energy infrastructure, it becomes easier to develop, finance, and integrate the remaining infrastructure required to meet our energy needs with locally available renewable resources.
Electrifying the heating/cooling and transport sector: Achieving 100% renewable energy will require increasing the interconnection between the electricity, the heating/cooling, and the transport sectors, allowing renewable electricity to be channeled to a wider range of dispatchable end-uses such as in thermal systems or in electric vehicles.
Maximizing opportunities for citizen participation and the development of new business models: At the heart of a successful 100 % renewable energy strategy, it is fundamental to allow open participation in the development and financing of energy infrastructure.
Educating and informing citizens and businesses: Implementing a 100% renewable energy strategy requires the participation of a variety of stakeholders, which makes both the breadth and the depth of awareness crucial to long-term success. Educating and informing the public as well as businesses about the renewable energy goal and its long-term benefits facilitates public support and acceptance.
Adopting an integrated approach to fiscal, economic & energy policy: A successful 100% renewable energy strategy requires an integrated approach across policy areas such as fiscal, energy, economic, and infrastructure policy.

NOW THEREFORE: I, Ardell F. Brede, Mayor of the City of Rochester do hereby proclaim that Rochester should apply for funding to develop a comprehensive energy plan that includes all three sectors: electric, transport, and heating/cooling. This plan should be done by a consulting firm with a proven record and experience in developing 100% renewable energy plans.

IN WITNESS WHEREOF, I have hereunto set my hand and caused the corporate seal of the City of Rochester to be affixed this 12th day of October, 2015.

Ardell F. Brede, Mayor
City of Rochester, Minnesota

* Concepts reprinted with permission from the booklet "HOW TO ACHIEVE 100 % RENEWABLE ENERGY". Commissioned by: The World Future Council, published September 2014.

BURNS McDONNELL

2015 Update of the RPU Infrastructure Study

rpu
we pledge, we deliver®

Rochester Public Utilities

Project No. 82902

June 2015

BURNS & McDONNELL

June 24, 2015

Mr. Wally Schlink
Director of Power Resources & Customer Relations
Rochester Public Utilities
4000 East River Road
Rochester, MN 55906

Re: 2015 Update to the Rochester Public Utilities Infrastructure Plan

Dear Mr. Schlink:

Rochester Public Utilities (RPU) retained Burns & McDonnell Engineering Co. (BMcD) to conduct an update to the RPU Infrastructure Plan that was started in 2005. The objective was to analyze the power supply needs of RPU from 2016 through 2035 in order to identify short-term, intermediate-term, and long-term infrastructure requirements for providing reliable, low cost electric power and thermal energy to its customers.

The following provides the overall highlights of the infrastructure plan update:

1. Positions RPU for long-term power supply with the expiration of the SMMPA Power Sales Contract (PSC) in 2030
2. Reduces direct dependence from coal resources within the RPU portfolio by 2030 and significantly reduces carbon emissions
3. Meets renewable standards and objectives: 25 percent by 2025 renewable standard, 1.5 percent solar standard, 1.5 percent conservation standard
4. Has the flexibility to accommodate potential sharp increases or decreases in load and energy requirements due to Mayo Clinic, Destination Medical Center development, or customer solar
5. Positions RPU for short-term and long-term compliance with environmental regulations
6. Retires an inefficient resource and modernizes the RPU generation fleet with high efficiency and low emission units
7. Expands partnership opportunities with the Mayo Clinic and other combined heat and power prospects

9400 Ward Parkway \ Kansas City, MO 64114
O 816-333-9400 \ F 816-333-3690 \ burnsmcd.com

BURNS McDONNELL

BMcD is pleased to submit our report to RPU detailing the results of the assessment. It has been a pleasure to assist RPU with this evaluation. If you have any questions regarding the information presented herein, please feel free to contact me at 816-822-3459 or mborgstadt@burnsmcd.com.

Sincerely,

Mike Borgstadt, PE
Manager, Business Consulting

MEB/meb

2015 Update of the RPU Infrastructure Plan

2015 Update of the RPU Infrastructure Study

prepared for

Rochester Public Utilities

Rochester, Minnesota

Project No. 82902

June 2015

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

TABLE OF CONTENTS

Page No.

LIST OF ABBREVIATIONS .... **I**

STATEMENT OF LIMITATIONS .... **III**

1.0 EXECUTIVE SUMMARY **1-1**
1.1 Study Objectives 1-1
1.2 Review of Power Supply Conditions 1-2
1.2.1 Overall Electricity Industry Trends 1-2
1.2.2 MISO Energy Market 1-3
1.2.3 RPU Load and Resources 1-5
1.3 Resource Analysis & Strategy 1-7
1.3.1 New Resources 1-7
1.3.2 Power Supply Analysis 1-7
1.4 Summary 1-8
1.5 Infrastructure Plan Highlights 1-10

2.0 INTRODUCTION **2-1**
2.1 Rochester Public Utilities Overview 2-1
2.2 Study Objectives 2-1
2.3 Study Background 2-1
2.4 Study Methodology 2-1
2.5 Study Organization 2-2

3.0 REVIEW OF POWER SUPPLY CONDITIONS **3-1**
3.1 General Power Supply Assumptions 3-1
3.2 Overall Electricity Industry Trends 3-1
3.3 MISO Energy Market 3-3
3.4 Load Forecast 3-6
3.5 Power Supply Resources 3-9
3.5.1 RPU Local Power Generating Resources 3-9
3.5.2 Southern Minnesota Municipal Power Agency Contract 3-10
3.6 Balance of Loads and Resources 3-10
3.7 Mayo Clinic Steam 3-11
3.8 Forecasts 3-12
3.8.1 Fuel Cost Forecast 3-13
3.8.2 Market Energy Cost Forecast 3-14
3.8.3 Market Capacity Cost Forecast 3-15
3.9 New Generation Resources 3-15

4.0 RESOURCE ANALYSIS & STRATEGY **4-1**

4.1 Power Supply Plan Model Development 4-2
4.2 Power Supply Analysis 4-2
4.3 Sensitivity Considerations 4-7

5.0 SUMMARY 5-1
5.1 Summary of Key Assumptions and Conclusions 5-1
5.2 Infrastructure Plan Highlights 5-2

APPENDIX A – POWER SUPPLY STUDY ASSUMPTIONS
APPENDIX B – NEW RESOURCE TECHNOLOGY ASSESSMENT
APPENDIX C – DISPATCH MODEL RESULTS

LIST OF TABLES

Page No.

Table 1-1: Power Supply Paths and Costs 1-8
Table 3-1: RPU Historical Energy Conservation and Spending 3-9
Table 3-2: New Resource Cost and Performance Summary 3-17
Table 4-1: Power Supply Paths and Costs 4-4

LIST OF FIGURES

Page No.

Figure 1-1: MISO Energy Market Area 1-3
Figure 1-2: MISO Energy Resource Mix (2014) 1-3
Figure 1-3: MISO Local Resource Zones 1-4
Figure 1-4: MISO Energy Historical LMP Price 1-5
Figure 1-5: RPU Balance of Loads and Resources 1-6
Figure 3-1: MISO Energy Market Area 3-3
Figure 3-2: MISO Energy Resource Mix (2014) 3-4
Figure 3-3: MISO Local Resource Zones 3-5
Figure 3-4: MISO Energy Historical LMP Price 3-6
Figure 3-5: RPU Demand Forecast 3-7
Figure 3-6: RPU Energy Forecast 3-8
Figure 3-7: RPU Balance of Loads and Resources 3-11
Figure 3-8: Mayo Clinic Hourly Steam Requirement Profile 3-12
Figure 3-9: Natural Gas Cost Forecast 3-13
Figure 3-10: Market Energy Cost Forecast 3-14
Figure 4-1: Total Annual Wholesale Power Supply Costs 4-5
Figure 4-2: Total Fixed Costs (Fixed O&M, Debt Service & Demand Charges) 4-5
Figure 4-3: Total Variable Costs (Variable O&M & Fuel) 4-6
Figure 4-4: Net Market Interactions (Purchases less Sales) 4-6

LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
BLR	balance of loads and resources
BMcD	Burns & McDonnell Engineering Co.
Btu	British thermal units
CCGT	combined cycle gas turbine
CHP	combined heat and power
CO_2	carbon dioxide
CONE	cost of new entry
CPP	Clean Power Plan
CROD	Contract Rate of Delivery via the SMMPA PSC
DMC	Destination Medical Center
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GOR	gross operating revenues
GW	gigawatt
hr	hour
IDC	interest during construction
kpph	kilopound per hour
kWh	kilowatt hour
klbs	kilopound
Lake Zumbro	Lake Zumbro Hydroelectric Plant
lbs	pounds
LDC	local distribution company
LMP	locational marginal pricing
LNG	liquefied natural gas
LRZ	load resource zone

Abbreviation	Term/Phrase/Name
Mayo	Mayo Clinic
MERC	Minnesota Energy Resources, Co.
MISO	MISO Energy (formerly Midwest Independent System Operator)
MMBtu	million British thermal units
MTEP	MISO Transmission Expansion Planning
MW	megawatt
MWh	megawatt hour
NERC	North American Reliability Corporation
NNG	Northern Natural Gas Company
NPV	net present value
O&M	operation and maintenance
OEM	original equipment manufacturer
OWEF	Olmsted Waste-to-Energy Facility
Plant	Cascade Creek Combustion Turbine Plant
PSC	Power Sales Contract with SMMPA
RPU	Rochester Public Utilities
SLP	Silver Lake Plant
SMMPA	Southern Minnesota Municipal Power Agency
Study	2015 Infrastructure Study
UCAP	unforced capacity
U.S.	United States

STATEMENT OF LIMITATIONS

In preparation of this Study, Burns & McDonnell Engineering Co. (BMcD) has relied upon information provided by Rochester Public Utilities (RPU). While BMcD has no reason to believe that the information provided, and upon which BMcD has relied, is inaccurate or incomplete in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness.

Estimates and projections prepared by BMcD relating to performance and costs are based on BMcD's experience, qualifications, and judgment as a professional consultant. Since BMcD has no control over weather, cost and availability of labor, material and equipment, labor productivity, contractors' procedures and methods, unavoidable delays, economic conditions, government regulations and laws (including interpretation thereof), competitive bidding, and market conditions or other factors affecting such estimates or projections, BMcD does not guarantee the accuracy of its estimates or predictions.

1.0 EXECUTIVE SUMMARY

This report section presents a summary of the 2015 Infrastructure Update Study (Study). The Study was completed by Burns & McDonnell Engineering Company (BMcD) for Rochester Public Utilities (RPU). The objectives, methodology, and results of the Study are summarized in the following sections.

1.1 Study Objectives

BMcD was retained by RPU to perform this Study building upon the previous infrastructure studies RPU has conducted in the past. This report provides information on the generation resource planning and other analyses undertaken to make updated decisions and recommendations on RPU's short-term and long-term strategy.

There continues to be significant impacts to utilities within the power industry due to economic conditions, costs of fuel, and regulatory issues. These impacts require electric utilities to continuously monitor their infrastructure and power supply requirements to provide reliable, low cost power to their customers. The objective of this Study was to analyze the power supply needs of RPU from 2016 through 2035 in order to identify short-term, intermediate-term, and long-term infrastructure requirements.

Due to the ever-changing power industry, RPU has monitored its power supply needs regularly by commissioning infrastructure studies starting in 2005 with updates conducted in 2009 and 2012. These previous studies included several supply and demand side activities which RPU could pursue. RPU has continued to aggressively pursue demand side measures that allow customers to reduce their energy consumption. The reductions have targeted an amount of 1.5 percent of the expected retail energy sales for the year. The programs include numerous appliance efficiency upgrades, lighting change out, and direct load control programs.

In addition to continued conservation measures, RPU has a need to address several issues associated with its electric supply portfolio and resources including the following:

- Consider the addition of a new, efficient resources that can limit RPU's exposure to market prices
- Ability to accommodate potential sharp increases in load and energy requirements due to the Destination Medical Center (DMC) and Mayo Clinic (Mayo)
- Position RPU for short-term and long-term compliance with environmental regulations (namely potential carbon dioxide (CO_2) regulations)
- Short-term issues associated with an aging Cascade Creek Unit 1 and potential difficulties obtaining bi-lateral market capacity contracts

- Intermediate-term considerations with the expiration of the steam contract with Mayo in 2025
- Long-term power supply concerns with the expiration of the Southern Minnesota Municipal Power Agency Power Sales Contract in 2030

1.2 Review of Power Supply Conditions

1.2.1 Overall Electricity Industry Trends

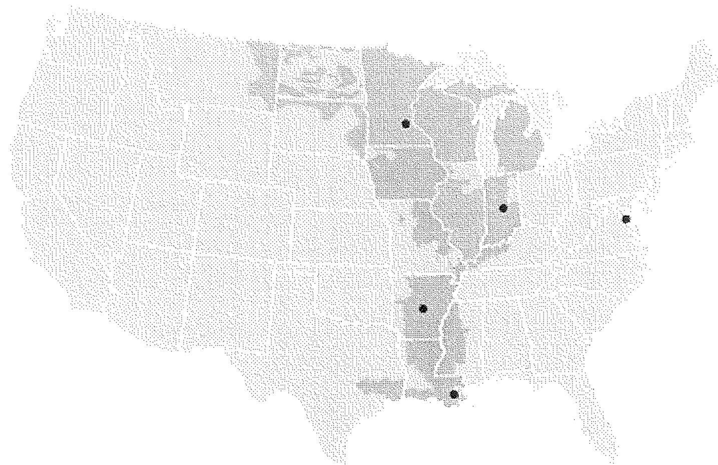
The electricity industry continues to be impacted by numerous trends. The following provides a brief discussion of the overall trends that are currently impacting electric utilities and generators.

- Environmental regulations: Both federal and state environmental regulating agencies continue to pursue more stringent environmental regulations regarding emissions from power generating facilities, specifically coal-fired power plants.
- Low natural gas prices: Natural gas prices remain low as production continues to outpace demand requirements, however industry forecasts appear to be fairly robust with price increases around five percent per year.
- Continued renewable development: Many state and federal regulators continue to pursue increased renewable portfolio and energy requirements.
- Relatively low load growth: While much of the U.S. has seen economic growth since the economic recession in the 2008 and 2009 timeframe, the recovery of demand and energy has been much slower. Increased conservation programs has also led to lower load growth.
- Low wholesale market energy prices: The combination of low natural gas prices, increased renewable development, and relatively low load growth has kept wholesale market energy prices low compared to historical averages.
- Coal-fired retirements: With the combination of all of the above factors, the investment in costly environmental compliance solutions at coal-fired power plants has reduced the overall economic benefit for many coal-fired plants and therefore coal-fired power plants are retiring.
- Increased interest in "firm" capacity: A number of factors have led to the increased interest in firm capacity including coal-fired retirements, recent extreme winter weather, and increased dependence of natural gas for the electric industry. If firm natural gas deliveries are required for power generators, it could increase the cost of production significantly.

1.2.2 MISO Energy Market

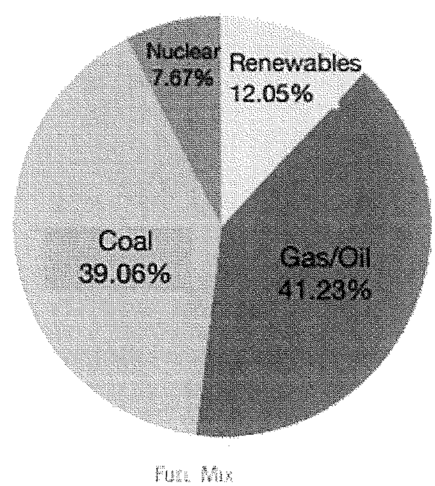
MISO initiated its energy market in 2005, at about the time of the issuance of the initial Infrastructure Plan. At the end of 2013, MISO added several utilities within the south, central portion of the U.S. The MISO market is made up of numerous utilities operating in the 15 states as presented in Figure 1-1.

Figure 1-1: MISO Energy Market Area



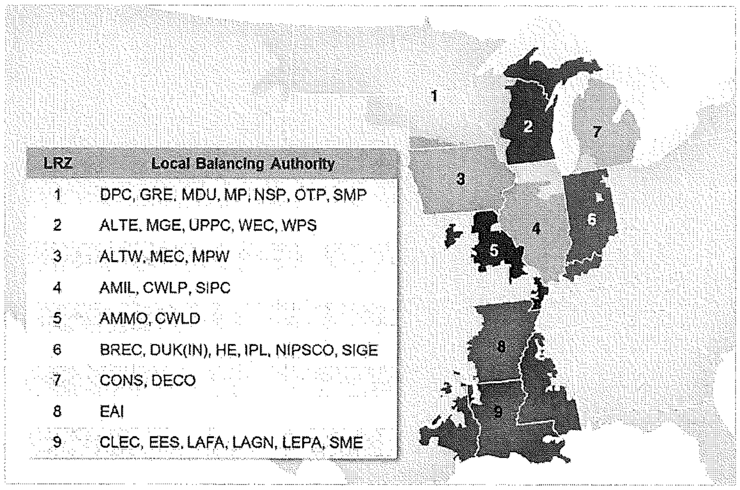
The addition of the southern area of the MISO market brought significantly more natural gas-fired generation resources into MISO. The mix of resources within MISO is shown in Figure 1-2.

Figure 1-2: MISO Energy Resource Mix (2014)



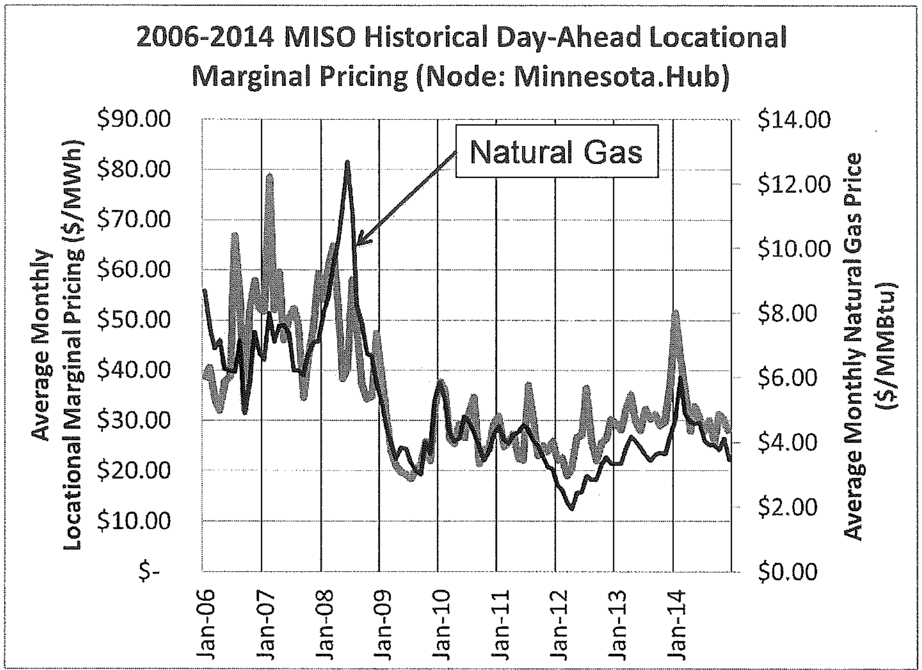
As part of the overall resource adequacy, MISO divided the overall MISO region into sub-regions called local resource zones (LRZ). Figure 1-3 presents an illustration of the LRZs within MISO. As illustrated within the graphic, RPU is located within LRZ 1. Though not required, most utilities procure capacity within their own LRZ to ensure they meet their capacity requirements. Capacity procured outside of a utility's LRZ may present a risk that the entire capacity is not credited toward their requirements should transmission limitations exist.

Figure 1-3: MISO Local Resource Zones



Utilities have become more accustomed to the market operations. It is common for utilities today to acquire all of their energy from the market and sell energy from their resources into the market when it is accepted for dispatch. In essence, all of the electrical energy RPU distributes above its contract with Southern Minnesota Municipal Power Agency (SMMPA) is acquired from the MISO market. The cost for this energy has been affected significantly from the initial operation of the market. The past few years have seen prices decline significantly from the peak year of 2007. Figure 1-4 provides annual averages of hourly locational marginal pricing (LMP) for day-ahead energy at the Minnesota Hub for several years.

Figure 1-4: MISO Energy Historical LMP Price



The decline in pricing is due to several factors including:

- Economic downturn and relatively slow economic and load growth
- Significant addition of wind resources (approximately 2 gigawatt (GW) in 2008 and now approximately 13 GW in 2014)
- Low pricing of natural gas

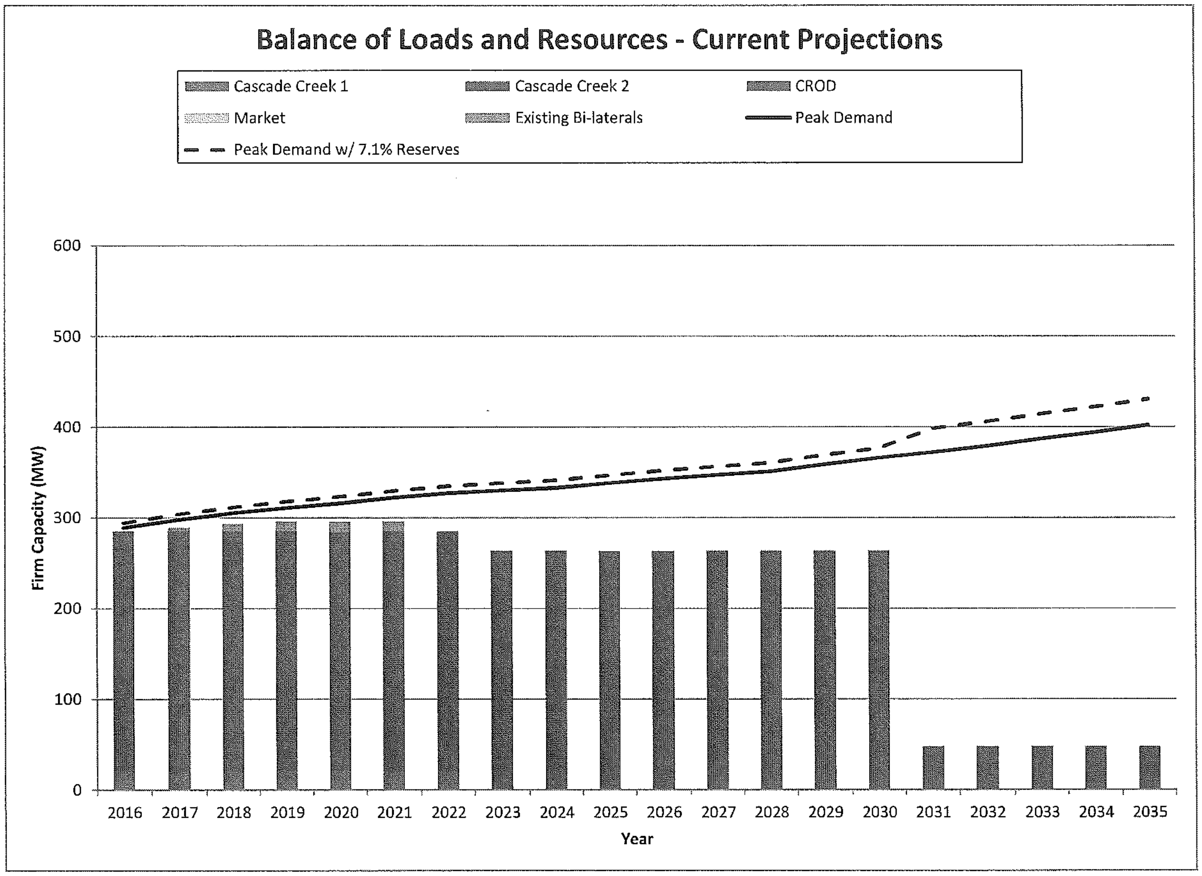
1.2.3 RPU Load and Resources

RPU's load forecast continues to be significantly below the initial forecast used in the 2005 Infrastructure Plan. The forecast used in this update is based on recent SMMPA projections, which was performed by a third-party company, Leidos, in compliance with MISO's standards. The adjusted forecast can be attributed to many factors including increased conservation programs and end-user efficiency. Therefore, it is inherently assumed in the forecast that the aggressive conservation reviewed in the initial Infrastructure Plan is capturing sufficient demand and energy to result in the SMMPA revised forecast.

In order for RPU to meet its load requirements, RPU has several power supply resources currently being utilized within its power supply portfolio including both local generation resources under RPU operating control and power supply contracts with other power generating entities.

A balance of loads and resources (BLR) based on the load forecast and resources that RPU will have available to meet its obligations are presented in Figure 1-5. Based on existing resources and current load projections, RPU will be capacity deficit both in the short-term and long-term, especially after the expiration of the SMMPA Power Sales Contract (PSC) Contract Rate of Delivery (CROD).

Figure 1-5: RPU Balance of Loads and Resources



In addition to the power supply contracts, RPU has a steam contract with the Mayo Clinic. Historically, RPU has provided Mayo with up to 50,000 pounds per hour (pph) of steam from one of the steam units at the Silver Lake Plant (SLP). As it was originally envisioned, the operation of the SLP on coal would allow the extraction of this steam for Mayo at a benefit for both parties. After the last Infrastructure Plan conducted in 2012 illustrated increased environmental regulation costs and dwindling economic benefits, RPU decided to retire SLP from coal-fired operation and electric generation altogether by the end of 2015. RPU has since elected to operate the existing SLP boilers utilizing natural gas fuel only. RPU will continue to provide approximately 50,000 pph of steam to Mayo through 2025.

1.3 Resource Analysis & Strategy

1.3.1 New Resources

The capacity and energy needs of RPU are projected to potentially increase substantially over the study period. There are two approaches to satisfy the capacity and energy obligations. These could be satisfied either from resources owned by RPU or contracted for through the market. Current EPA regulations have removed a new coal-fired power plant from consideration as a new resource. Therefore, gas-fired and renewable resources are the only realistic resource options that RPU could construct. The following resources were considered within this assessment:

- Reciprocating engine plant
- Simple cycle gas turbine aeroderivative technology
- Simple cycle gas turbine frame technology
- Combined cycle gas turbine (CCGT) frame technology
- Combined heat and power (CHP) facility
- Wind generation
- Solar generation

When RPU-owned resources were not available or economical, a bi-lateral contract for market capacity from an accredited resource was used to maintain reserve margins throughout the study period. Market capacity resources are modeled as temporary supply resources, expiring at the end of each year.

1.3.2 Power Supply Analysis

Utilizing the assumptions herein, BMcD developed future power supply plans utilizing the software program Strategist. Strategist evaluates thousands of combinations of power supply options for RPU to meet its load requirements. After Strategist developed several power supply paths, BMcD then evaluated the paths within the hourly dispatch commitment software of Promod. Table 1-1 presents the results of the dispatch analysis.

As presented in Table 1-1, Strategist developed four unique power supply paths for RPU. Appendix C presents the detailed results for each of the four paths. The following provides general observations for the power supply paths:

1. SMMPA PSC expires at the end of 2030.
2. A combined cycle gas turbine facility is added in 2031.
3. Solar and wind generation is added to meet state requirements.

4. Each case relies on purchases of capacity from the market, though the timing and magnitude vary depending on when each new resource is added.
5. Each case retires Cascade Creek Unit 1 and adds a reciprocating engine facility and CHP facility, though the timing of the installations is varied across the cases.
6. All four cases are very close in cost as illustrated with the net present value (NPV) for each case within 1.2 percent.

Table 1-1: Power Supply Paths and Costs

Path No.	1	2	3	4
Plan Year	**Retire CC1 2023, Install Peaker 2023**	**Retire CC1 2018, Install Peaker 2019**	**Retire CC1 2018, Install Peaker 2018**	**Retire CC1 2018, Install Peaker 2018, Install CHP 2026**
2016	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
2017				
2018		Retire CC1	Retire CC1 Peaker (50MW)	Retire CC1 Peaker (50MW)
2019		Peaker (50MW)		
2020				
2021	Solar (3MW)	Solar (3MW)	Solar (3MW)	Solar (3MW)
2022				
2023	Retire CC1 Peaker (50MW)			
2024				
2025				
2026				CHP (30MW)
2027				
2028	Solar (3MW)	Solar (3MW)	Solar (3MW)	Solar (3MW)
2029	CHP (30MW)	CHP (30MW)	CHP (30MW)	
2030				
2031	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)
2032				
2033	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
2034				
2035	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
NPV Cost ($000) *% Difference*	$1,498,056 *0.00%*	$1,506,011 *0.53%*	$1,507,624 *0.64%*	$1,515,469 *1.16%*

1.4 Summary

Based on the analysis presented herein, BMcD provides the following conclusions and recommendations:

1. Environmental groups and agencies continue to aggressively target coal-fired plants in regards to emissions.
   a. This will lead to additional coal-fired plant retirements.
   b. Increased retirements are anticipated to reduce market capacity availability and increase MISO energy prices.
2. With the retirement of SLP from electric generation, RPU lost its "middle of the road" hedge against MISO energy prices.
3. Due to its advanced age, continued operation of Cascade Creek Unit 1 may present additional risks
   a. Facing increased maintenance costs, inefficiency, lack of original equipment manufacturer (OEM) support, and questionable availability of spare parts
   b. Difficult to participate in MISO energy market
4. The infrastructure plans includes:
   a. Voluntary compliance with State of Minnesota renewable mandates
   b. Compliance with proposed CO_2 regulations
   c. Allows RPU to begin the transition away from joint action agency (SMMPA PSC)
   d. It may provide partnering opportunities after SMMPA PSC with other utilities
5. The infrastructure plan provides insight to several windows:
   a. Short-term: The addition of peaking resource and retirement of Cascade Creek 1 will allow RPU to maintain an appropriate amount of risk to market capacity pricing while also allowing RPU to control the retirement of Cascade Creek 1.
   b. Intermediate-term: The addition of a CHP facility appears favorable for RPU within its power supply portfolio and Mayo.
   c. Long-term: The likely replacement of SMMPA PSC is a combination of a CCGT unit and renewable generation.
6. Based on the current economic and market environment, there are several considerations for earlier development of peaking resource:
   a. Interest rates are currently low
   b. The current currency exchange rate (Euro to Dollar) is favorable for reciprocating engines which are primarily priced with the Euro.
   c. Controls capacity risk exposure (controls retirement of Cascade Creek 1)
   d. The capacity market within MISO has shown decreased availability of capacity and increased cost.
   e. Provides a replacement energy-hedge with the retirement of SLP and Cascade Creek 1

   f. Protects against exposure of Cost of New Entry (CONE) pricing, which is approximately $90,000 per megawatt (MW) per year with no benefit of energy revenue or asset investment.

7. RPU should continue to update the analysis of its future resource plans as major changes in the industry occur or as assumptions change from those used herein.

1.5 Infrastructure Plan Highlights

The following provides the overall highlights of the infrastructure plan update:

1. Positions RPU for long-term power supply with the expiration of the SMMPA Power Sales Contract (PSC) in 2030
2. Eliminates coal from the RPU portfolio by 2030 and significantly reduces carbon emissions
3. Meets renewable standards and objectives: 25 percent by 2025 renewable standard, 1.5 percent solar standard, 1.5 percent conservation standard
4. Has the flexibility to accommodate potential sharp increases or decreases in load and energy requirements due to DMC and customer solar
5. Positions RPU for short-term and long-term compliance with environmental regulations
6. Retires inefficient resource and modernizes the RPU generation fleet with high efficiency and low emission units
7. Expands partnership opportunities with the Mayo Clinic and other combined heat and power prospects

2.0 INTRODUCTION

Burns & McDonnell Engineering Company (BMcD) was retained by Rochester Public Utilities (RPU) to perform an Infrastructure Study (Study) building upon the previous infrastructure studies RPU has conducted in the past. This report provides information on the generation resource planning and other analyses undertaken to make updated decisions and recommendations on RPU's short-term and long-term strategy.

2.1 Rochester Public Utilities Overview

Rochester Public Utilities provides electric and water utilities to approximately 100,000 residents of Rochester, Minnesota. RPU has approximately 50,000 electric customers with a peak summer load of approximately 300 megawatt (MW). Additionally, RPU serves the Mayo Clinic (Mayo) providing both a portion of its electric and steam requirements.

2.2 Study Objectives

There continues to be significant impacts to utilities within the power industry due to the economic conditions, costs of fuel, and regulatory issues. These impacts require electric utilities to continuously monitor their infrastructure and power supply requirements to provide reliable, low cost power to their customers. The objective of this Study was to analyze the power supply needs of RPU from 2016 through 2035 in order to identify short-term, intermediate-term, and long-term infrastructure requirements.

2.3 Study Background

Due to the ever-changing power industry, RPU has monitored its power supply needs regularly by commissioning infrastructure studies starting in 2005 with updates conducted in 2009 and 2012. These previous studies included several supply and demand side activities which RPU could pursue. RPU has continued to aggressively pursue demand side measures that allow customers to reduce their energy consumption. These reductions have targeted an amount of 1.5 percent of the expected retail energy sales for the year. The programs include numerous appliance efficiency upgrades, lighting change out and direct load control programs. This Study provides a discussion of the progress that RPU has made in the area of demand side management and energy efficiency.

2.4 Study Methodology

The analysis of power supply options and issues required the projection of RPU's demand and energy over the study period. The forecast for the energy and demand was provided by RPU. The forecast was used as the basis for determining when additional resources would be needed to maintain the capacity reserve margins required by the MISO Energy (MISO, formerly known as Midwest Independent System Operator) and North American Electric Reliability Corporation (NERC).

The analysis of power supply options was performed using the Strategist resource expansion program and Promod hourly unit commitment dispatch model. The Strategist program analyzes the capacity and energy needs of a utility and adds resources from options provided to the software program. Strategist performs thousands of combinations evaluating the different resource portfolios. The Promod software program then takes power supply paths developed in Strategist and simulates hourly dispatch each year over the course of the study period. Various assumptions were developed for such things as capital costs, fixed operations and maintenance costs, fuel supply costs, and variable operating costs of potential new resources. In addition, BMcD developed assumptions for market costs at a representative RPU MISO node. The time frame for the updated resource analysis was from 2016 through 2035.

2.5 Study Organization

This study is organized into several sections as follows:

- Section 1.0: Executive Summary – Provides an executive summary of the Study
- Section 2.0: Introduction – Provides an introduction to the Study
- Section 3.0: Review of Power Supply Conditions – Details of the status of RPU power supply resources, system, and key forecast.
- Section 4.0: Resource Analysis & Strategy – Details the economic analysis evaluating the resource plans including the methodology and results.
- Section 5.0: Summary – Provides a summary of the assumptions and conclusions reached within this Study.

3.0 REVIEW OF POWER SUPPLY CONDITIONS

This section provides information regarding RPU's general power supply assumptions, local generating resources, power supply contracts, and key forecasts utilized within this Study.

3.1 General Power Supply Assumptions

The analysis began with the development of the baseline assumptions and constraints as applicable for RPU. The following general assumptions are applicable to the analysis:

- The study period covers the years 2016 through 2035.
- The hourly load used in this Study was based on information from 2013.
- The interest rate for RPU for financing terms was 5 percent, with resources financed over 30 years.
- The general escalation rate was assumed to be 2.5 percent.
- The discount rate was assumed to be 5 percent.

3.2 Overall Electricity Industry Trends

The electricity industry continues to be impacted by numerous trends. The following provides a brief discussion of the overall trends that are currently impacting electric utilities and generators.

- Environmental regulations: Both federal and state environmental regulating agencies continue to pursue more stringent environmental regulations regarding emissions from power generating facilities, specifically coal-fired power plants. One of the most recent regulations proposed by the U.S. Environmental Protection Agency (EPA) was the Clean Power Plan (CPP) specifically targeting a reduction in carbon dioxide (CO_2) emissions from existing coal-fired power plants through several avenues including performance improvements, fuel switching, and increased renewables and energy conservation.
- Low natural gas prices: Natural gas prices remain low as production continues to outpace demand requirements. Increased production is attributable to enhancements in fracking methods and technology. However, environmentalists and regulators continue to evaluate and debate the overall impacts on the environment due to fracking, and increased regulations, and thus increased costs, may be imposed. Furthermore, there is increased interest in developing liquefied natural gas (LNG) export facilities to allow for the U.S. and Canada to export natural gas to world markets with 21 proposed LNG export terminals in various stages of development across the U.S. and Canada (according to information from the Federal Energy Regulatory Commission (FERC)).

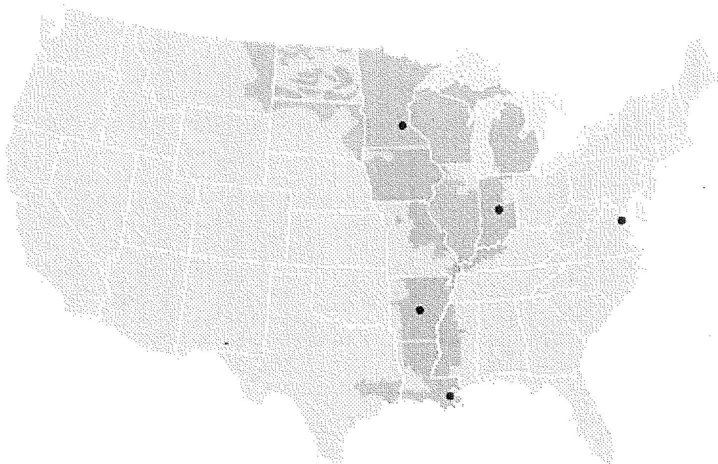
- Continued renewable development: In addition to the proposed CPP, many States continue to pursue increased renewable portfolio and energy requirements. Currently the federal government has tax incentives in place that incentivize renewable development through investment or production tax credits. While these tax credits are set to expire at the end of 2016, it remains to be seen if they will be extended as Congress has previously done.
- Relatively low load growth: While much of the U.S. has seen economic growth since the economic recession in the 2008 and 2009 timeframe, the recovery of demand and energy has been much slower. Most of the U.S. has experienced relatively low load growth recently, with a few exceptions revolving around the oil/gas boom. Increased conservation programs have led to slower load growth as well. RPU has experienced relatively average growth compared to the U.S. overall which has been around one percent.
- Low wholesale market energy prices: The combination of low natural gas prices, increased renewable development, and relatively low load growth has kept wholesale market energy prices low compared to historical averages. Wholesale market energy prices typically do not reflect fixed cost investments into resources, thus only reflect the variable and fuel cost components of energy production. With low natural gas prices, renewable generation being "dumped" to the market, and slower demand growth, market energy prices remain low.
- Coal-fired retirements: With the combination of all of the above factors, the investment in costly environmental compliance solutions at coal-fired power plants has reduced the overall economic benefit for many coal-fired plants. With the uncertainty in CO_2 regulations and dwindling economics, many coal-fired power plants have elected to cease coal-fired operation. Estimates of approximately 70 gigawatt (GW) of coal-fired capacity may be retired by 2020, representing approximately 25 percent of the entire U.S. coal-fired fleet.
- Increased interest in "firm" capacity: A number of factors have led to the increased interest in firm capacity including coal-fired retirements, recent extreme winter weather, and increased dependence of natural gas for the electric industry. As the regulations and economics drive the electric industry to increase its dependence on natural gas, the ability to provide firm capacity, especially during winter months, is a concern. Historically, natural gas-fired power plants were dispatched during the summer to meet increased demand due to air conditioning needs, when there is little competition for natural gas supply and deliveries. However, with the increased coal-fired power plant retirements, more natural gas-fired generation is going to be required during winter months when increased natural gas demand is prevalent due to residential and commercial heating needs. As such, many of the independent system operators are evaluating the overall reliability of the bulk electric system, especially during winter months, with increased reliance on

natural gas-fired power plants. If firm natural gas deliveries are required for power generators, it could increase the cost of production significantly.

3.3 MISO Energy Market

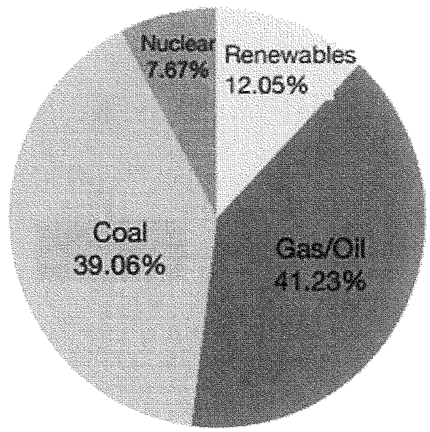
MISO initiated its energy market in 2005, at about the time of the issuance of the initial Infrastructure Plan. At the end of 2013, MISO added several utilities in the south-central portion of the U.S. The MISO market is made up of numerous utilities operating in the 15 states as presented in Figure 3-1.

Figure 3-1: MISO Energy Market Area



The MISO market has a peak load of approximately 127,000 MW. It has resources of approximately 180,000 MW with which to meet this load demand. In addition to these dispatchable resources, MISO has over 13,000 MW of wind generation in its market. The addition of the southern area of the MISO market brought significantly more natural gas-fired generation resources into MISO. The mix of resources within MISO is shown in Figure 3-2.

Figure 3-2: MISO Energy Resource Mix (2014)

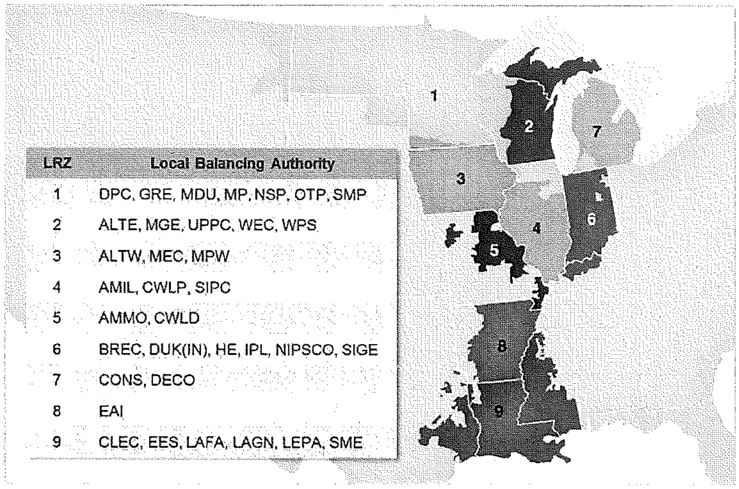


This market allows utilities to operate as they traditionally have and dispatch units they control to satisfy their load or to sell energy from their generation resources into the market and to purchase energy to meet their load requirements from the market. These purchase and sale transactions are performed on a daily basis. Over time, utilities have transitioned to selling generation into the market and procuring energy from the market.

Load serving utilities have two basic obligations in the MISO market. The first is to meet the capacity requirements for peak load demand plus reserve margin. The second is to be able to satisfy the energy requirements of its customers.

The market has matured and evolved in its business practices and standards for utilities. As a participant in the MISO market, RPU is subject to the business practices established by MISO and the MISO tariffs. One of these requirements is to maintain capacity reserves above its peak load obligations. MISO recently revised its capacity obligation requirements to be a function of a resource's overall reliability. Also, MISO recently launched a capacity auction process, however much of the capacity traded between utilities within MISO is still conducted via bi-lateral contracts. As part of the overall resource adequacy, MISO divided the overall MISO region into sub-regions called local resource zones (LRZ). Figure 3-3 presents an illustration of the LRZs within MISO. As illustrated within the graphic, RPU is located within LRZ 1. Though not required, most utilities procure capacity within their own LRZ to ensure they meet their capacity requirements. Capacity procured outside of a utility's LRZ may present a risk that the entire capacity is not credited toward their requirements should transmission limitations exist. In the event a utility does not procure sufficient capacity to meet its requirements, that utility may be exposed to short-term capacity penalty through MISO represented by the cost of new entry (CONE) pricing, which was approximately $90,000/MW-year recently that provides no benefit of energy revenue or asset investment.

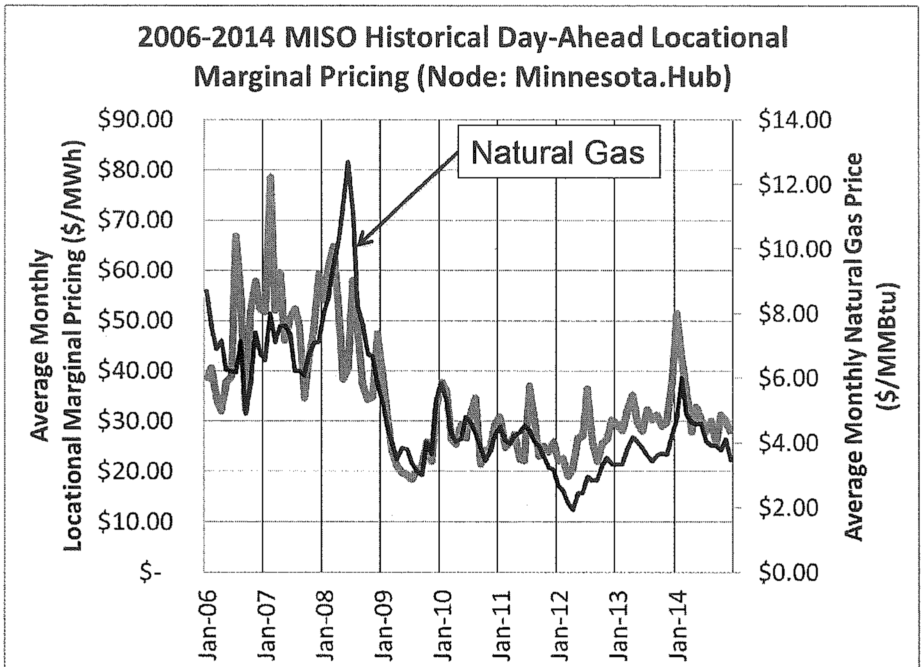
Figure 3-3: MISO Local Resource Zones



LRZ	Local Balancing Authority
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, DUK(IN), HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA, SME

Utilities have become more accustomed to the market operations. It is common for utilities today to acquire all of their energy from the market and sell energy from their resources into the market when it is accepted for dispatch. In essence, all of the electrical energy RPU distributes above its contract with SMMPA is acquired from the MISO market. The cost for this energy has been affected significantly from the initial operation of the market. The past few years have seen prices decline significantly from the peak year of 2007. Figure 3-4 provides annual averages of hourly locational marginal pricing for day ahead energy at the Minnesota Hub for nine years.

Figure 3-4: MISO Energy Historical LMP Price



The decline in pricing is due to several factors including:

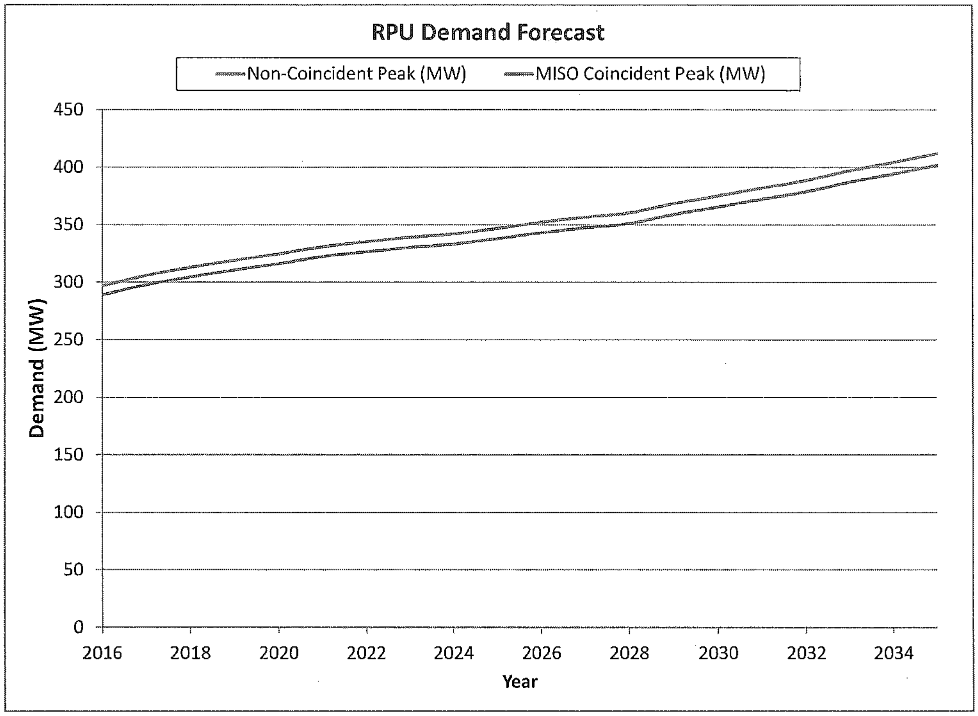
- Economic downturn and relatively slow economic and load growth
- Significant addition of wind resources (approximately 2 GW in 2008 and now approximately 13 GW in 2014)
- Low pricing of natural gas

Many utilities are able to take advantage of this pricing condition and acquire energy from the market much more economically than they could from operating their own generating assets. This has led many utilities to adopt a strategy of either contracting or installing low capital cost assets to meet the capacity obligations for load and reserves. They then buy energy from the market at a more economical average cost than is possible if they were to run the resources themselves. When possible, energy is sold from the resource into the market and this revenue is used to reduce the average power cost of the utility. Due to the attractive pricing in the MISO market, many small to medium sized utilities, such as RPU, are able to purchase energy at pricing well below their ability to generate it from their resources.

3.4 Load Forecast

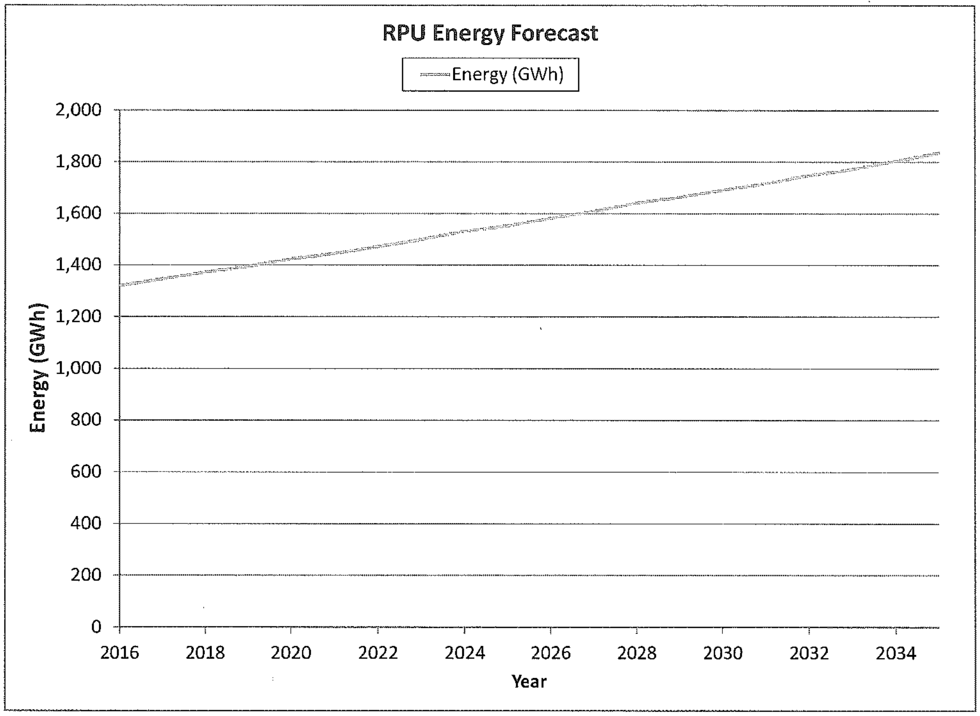
MISO requires that all members conduct an annual load forecast that has a well-defined methodology. RPU's annual forecast is developed by a third-party company, Leidos, through SMMPA. The load forecast was based on a recent SMMPA projection for RPU demand and energy requirements to 2030. The forecasts for demand and energy are summarized on an annual basis over the study period in Figure 3-5 and Figure 3-6, respectively.

Figure 3-5: RPU Demand Forecast



Note: The demand forecast for RPU was developed within SMMPA's planning process.

Figure 3-6: RPU Energy Forecast



Note: The energy forecast for RPU was developed within SMMPA's planning process.

RPU's load forecast continues to be significantly below the initial forecast used in the 2005 Infrastructure Plan. The forecast used in this update is based on recent SMMPA projections. The adjusted forecast can be attributed to many factors including increased conservation programs and end-user efficiency. Therefore, it is inherently assumed in the forecast that the aggressive conservation reviewed in the initial Infrastructure Plan is capturing sufficient demand and energy to result in the SMMPA revised forecast. Table 3-1 provides the estimated savings and cost of capturing the conserved energy and demand reductions.

Table 3-1: RPU Historical Energy Conservation and Spending

		Energy Conservation			Spending on Conservation Programs		
Year	Statute Requirement	Requirement (kWh)	Actual (kWh)	Percent to Goal	Required Spending	Actual Spending	Percent to Goal
2002	1.5% of GOR spending	169,000	7,562,201	4475%	$1,181,305	$1,115,327	94%
2003	1.5% of GOR spending	6,332,853	7,859,697	124%	$1,222,921	$1,327,321	109%
2004	1.5% of GOR spending	8,424,789	9,827,569	117%	$1,208,957	$1,167,760	97%
2005	1.5% of GOR spending	8,424,689	7,743,700	92%	$1,222,924	$1,213,517	99%
2006	1.5% of GOR spending	9,855,000	10,417,072	106%	$1,363,203	$1,377,074	101%
2007	1.5% of GOR spending	11,325,000	15,819,295	140%	$1,363,203	$1,995,606	146%
2008	1.5% of GOR spending	12,704,000	13,665,636	108%	$1,535,535	$1,698,407	111%
2009	0.75% Savings/1.5% Spending	16,274,333	16,994,220	104%	$1,744,800	$2,303,375	132%
2010	1.5% Savings / 1.5% Spending	19,100,443	19,126,719	100%	$1,814,398	$3,088,665	170%
2011	1.5% Savings / 1.5% Spending	19,100,443	20,420,120	107%	$1,896,508	$2,908,226	153%
2012	1.5% Savings / 1.5% Spending	18,785,066	23,248,077	124%	$1,926,061	$3,249,817	169%
2013	1.5% Savings / 1.5% Spending	18,563,927	29,842,896	161%	$1,893,582	$2,491,109	132%
2014	1.5% Savings / 1.5% Spending	18,610,704	22,102,056	119%	$1,932,964	$2,424,762	125%

Note: GOR is an abbreviation for gross operating revenues

3.5 Power Supply Resources

RPU has several power supply resources currently being utilized within its power supply portfolio including both local generation resources under RPU operating control and power supply contracts with other power generating entities. The following paragraphs provide information regarding these resources. Additional information regarding these resources is provided in Appendix A.

3.5.1 RPU Local Power Generating Resources

3.5.1.1 Cascade Creek Combustion Turbines

RPU owns and operates the Cascade Creek Combustion Turbines (Plant) located in Rochester that utilizes both fuel oil and natural gas to generate electricity. Specific details on the performance and costs of the units are presented in Appendix A.

Unit 1 is a nominal 27 MW combustion turbine that was commercial installed in 1975 and utilizes both natural gas and fuel oil. By today's standards Unit 1 is inefficient with a heat rate over 15,000 British thermal unit (Btu) per kilowatt-hour (kWh). Due to its advanced age, Unit 1 is going to require significant capital expenditures in the coming years in order to keep it operational. Furthermore, since the turbine is 40 years of age, the availability of spare parts is questionable moving forward.

Unit 2 consists of a natural gas-fired combustion turbine with a nominal output of approximately 48 MW. Unit 2 was installed in 2002.

Both combustion turbines are dispatched into the MISO market as peaking resources.

The city of Rochester, and the Plant, is served locally by the local distribution company (LDC) Minnesota Energy Resources, Co (MERC). MERC receives gas from the area interstate pipeline network at a high pressure. The pressure is reduced and distributed through a network of pipes within Rochester to retail consumers. Currently, RPU receives natural gas from MERC/Constellation/Northern Natural Gas (NNG) through an interruptible supply tariff. Historically during cold weather conditions, the gas suppliers have limited natural gas deliveries to RPU.

3.5.1.2 Lake Zumbro Hydroelectric

Lake Zumbro Hydroelectric Plant (Lake Zumbro) was built in 1920. Lake Zumbro has consistently provided RPU with a renewable supply of energy. The facility consists of a powerhouse and a 440-foot spillway built across the Zumbro River. The General Electric generators are driven at 225 revolutions per minute by 1,800-horsepower, Francis-type hydraulic turbines. This equates to approximately 1,300 kilowatts per wheel, which rates the station at an output of 2.6 MW.

3.5.1.3 Other Local Resources

In addition to the Plant and Lake Zumbro, RPU receives capacity and energy from several other resources including:

- Olmsted Waste-to-Energy Facility (OWEF): Energy resource only up to 5 MW
- IBM: Peak shaving resource approximately 3.6 MW

3.5.2 Southern Minnesota Municipal Power Agency Contract

In addition to the local power generation facilities described above, RPU has a PSC with SMMPA through CROD. The PSC with SMMPA is set to expire on December 31, 2030. The accounting of this energy is provided through the MISO settlement process and the contract with SMMPA. This contract requires RPU to purchase all of the retail energy it distributes at or below a rate of 216 MW per hour from SMMPA.

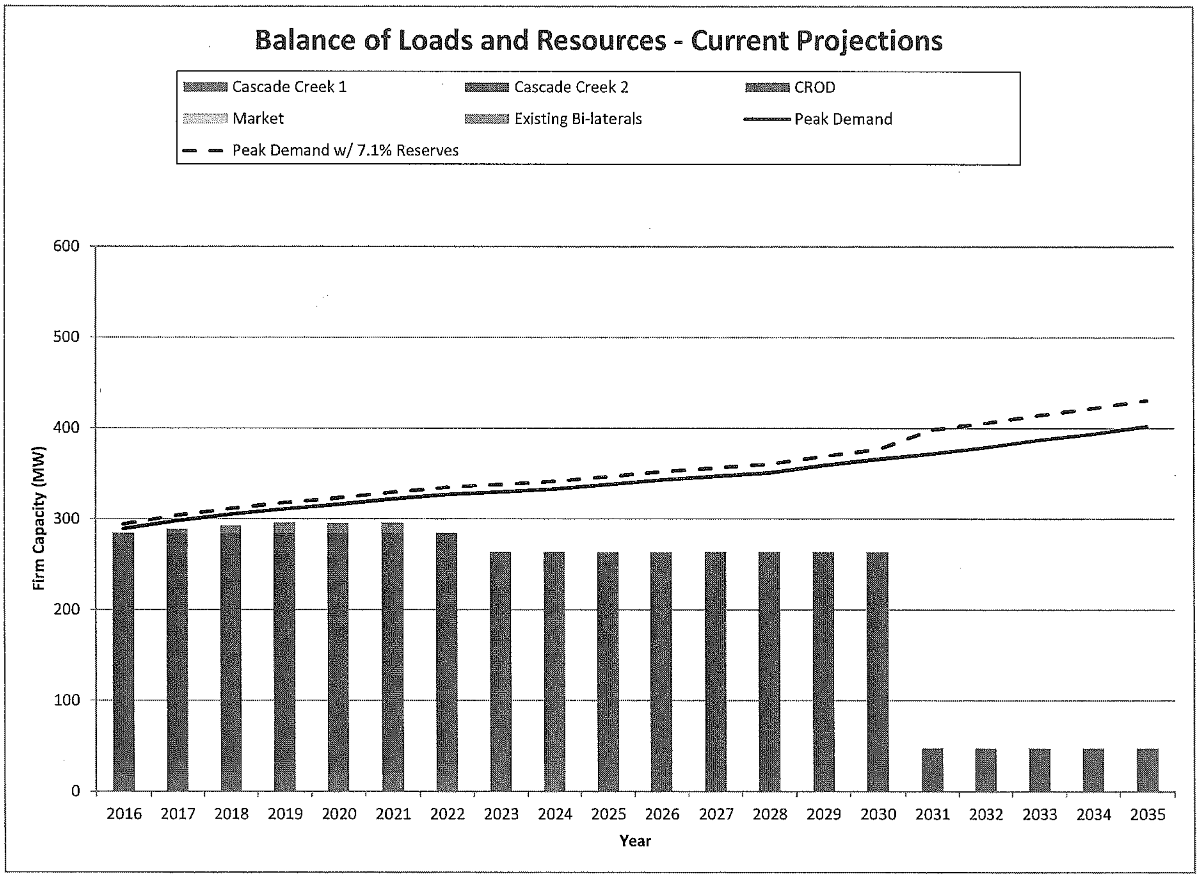
Specific details of the costs of the PSC discussed here are presented in Appendix A.

3.6 Balance of Loads and Resources

As described above, RPU has a number of resources to meet its capacity reserve margin requirements and renewable energy objectives. RPU meets a significant amount of its power supply obligations through its contract with SMMPA, which currently runs through 2030.

A balance of loads and resources (BLR) based on the load forecast and resources that RPU will have available to meet its obligations are presented in Figure 3-7. The reserve margin is based on RPU maintaining a margin of 7.1 percent for its load above CROD and under MISO's Module E Unforced Capacity (UCAP) resource adequacy method. As presented in Figure 3-7, Cascade Creek 1 is assumed to be retired from operation no later than the end of 2022 due to its age. Based on existing resources and current load projections, RPU will be capacity deficit both in the short-term and long-term, especially after the expiration of the SMMPA PSC CROD.

Figure 3-7: RPU Balance of Loads and Resources

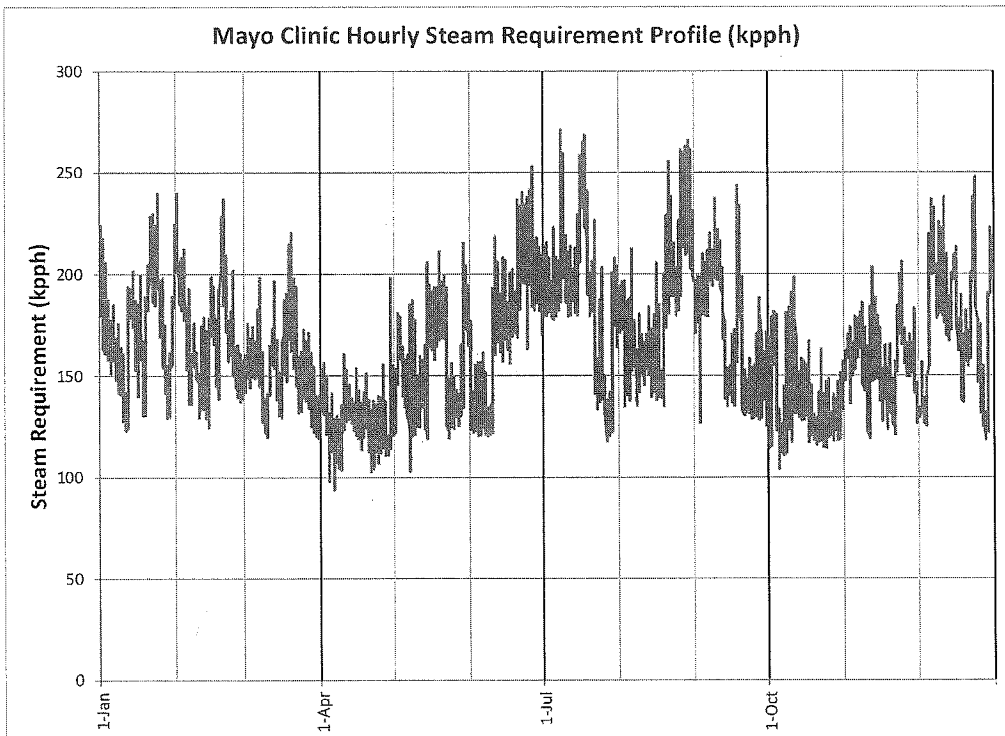


3.7 Mayo Clinic Steam

In addition to the power supply contracts, RPU has a steam contract with the Mayo Clinic. Historically, RPU has provided Mayo with up to 50,000 pph of steam from one of the steam units at the Silver Lake Plant (SLP). As it was originally envisioned, the operation of the SLP on coal would allow the extraction of this steam for Mayo at a benefit for both parties. After the last Infrastructure Plan conducted in 2012 illustrated increased environmental regulation costs and dwindling economic benefits, RPU decided to retire the Silver Lake Plant (SLP) from coal-fired operation and electric generation altogether by the end of 2015. RPU has since elected to operate the existing SLP boilers utilizing natural gas fuel only. RPU will continue to provide approximately 50,000 pph of steam to Mayo through 2025.

Overall, Mayo's internal steam and heat requirements are significantly higher than 50,000 pph and Mayo currently generates much of its heating requirements with internal power and steam producing equipment. Figure 3-8 presents a representative overall hourly steam requirement profile for the Mayo clinic.

Figure 3-8: Mayo Clinic Hourly Steam Requirement Profile



As presented in Figure 3-8, Mayo's steam requirements fluctuate from approximately 100 kilopounds per hour (kpph) to over 250 kpph. Both RPU and Mayo have indicated willingness to potentially partner with a combined heat and power (CHP) facility that would provide mutual benefits to both parties.

3.8 Forecasts

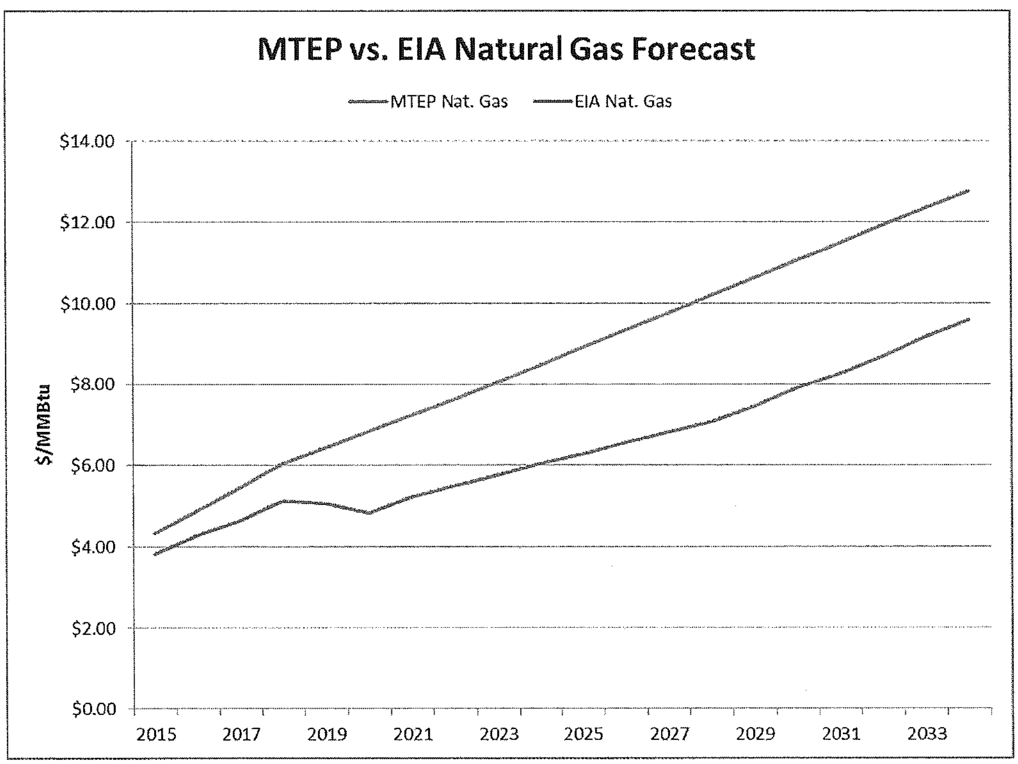
In order to conduct a long-term resource planning assessment for power supply, several forecasts have to be developed for evaluation. For this Study, BMcD developed key forecasts for fuel costs and market energy costs using reputable publicly available sources. The following paragraphs provide a summary of the forecasts developed and utilized within this Study. Further details of the forecasts are presented in Appendix A.

3.8.1 Fuel Cost Forecast

As part of its planning process to ensure electric grid reliability, MISO conducts numerous comprehensive studies of anticipating load, generation, and transmission projects. Part of this planning process requires MISO to project the cost of fuel and market energy. Within this Study, BMcD utilized the fuel forecast developed by MISO within MISO's transmission expansion planning (MTEP). MISO evaluates numerous futures considering varying levels of environmental regulation, renewable requirements, and economic growth. Using this data, BMcD developed a fuel forecast to utilize within this Study.

To compare the MTEP fuel forecast, BMcD also utilized projected information regarding natural gas fuel cost developed by the Department of Energy's (DOE) Energy Information Administration (EIA). Utilizing multiple forecasts that are considerably different provides the ability to assess the resource plan under varying assumptions. This provides for a more robust evaluation to determine whether one resource path appears more favorable under a different set of economic forecasts. Figure 3-9 presents both the MTEP and EIA natural gas forecasts. The MTEP forecast served as a basis for this Study.

Figure 3-9: Natural Gas Cost Forecast



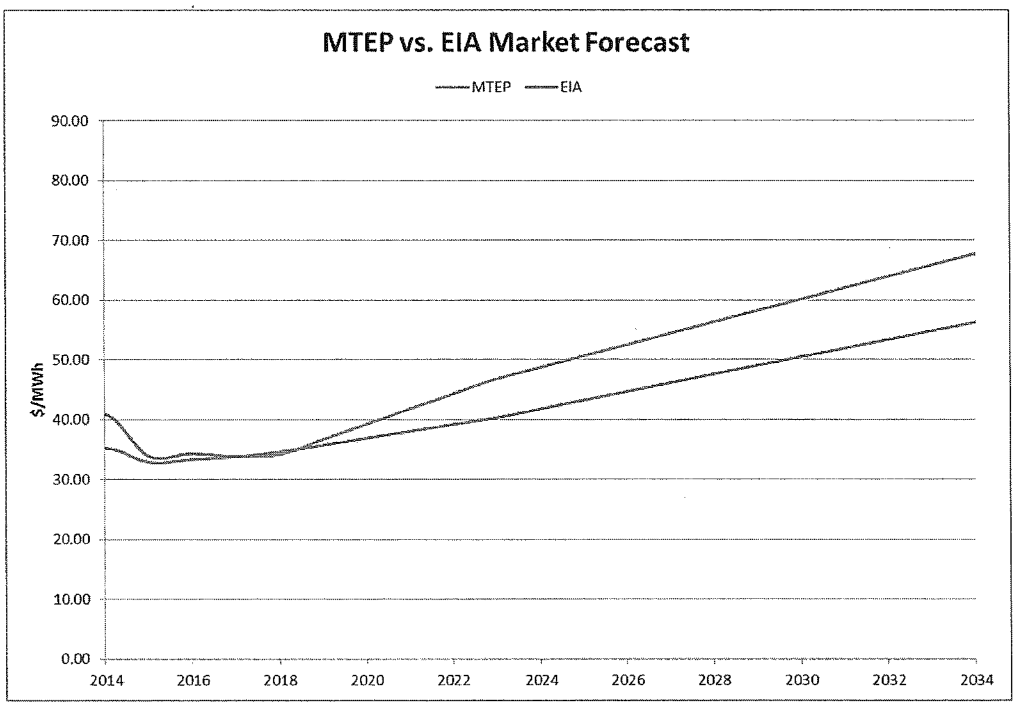
As presented in Figure 3-9, in the near term (from 2015 to 2019) both the MTEP and EIA natural gas forecasts are nearly the same. However, in the long-term (beyond 2020) the MISO MTEP fuel forecast is higher by approximately 15 to 20 percent.

3.8.2 Market Energy Cost Forecast

Similar to the discussion above regarding the natural gas cost forecast, BMcD utilized the market energy forecast developed by MISO within MISO's transmission expansion planning. Specifically, BMcD utilized the MTEP forecasted locational marginal pricing (LMP) for RPU. MISO evaluates numerous futures considering varying levels of environmental regulation and economic growth. Using the MTEP futures and data, BMcD developed a market energy forecast to utilize within this Study.

In addition to using the MISO data, BMcD also utilized the fuel cost forecast information developed by the EIA and made adjustments to the market energy cost forecast to account for a lower projected cost of natural gas. Figure 3-10 presents the market energy cost forecast utilizing both the MISO MTEP values and the EIA values.

Figure 3-10: Market Energy Cost Forecast



As illustrated in Figure 3-10, the market energy cost forecast for MTEP and EIA follows the same trend as the natural gas cost forecast, with both forecasts being fairly similar in the near-term. However, long-term the MTEP forecast is considerably higher by 15 to 20 percent. For this Study, BMcD utilized the MTEP forecast for market energy prices as the base assumption.

3.8.3 Market Capacity Cost Forecast

Capacity in the MISO market is required for utilities to meet their reserve margin obligations. The MISO market does include a specific market for capacity. However, utilities are not forced to participate within the capacity market auction and much of the capacity is traded on a bi-lateral basis between parties. Utilities can contract from a variety of parties to meet their capacity obligations, but are encouraged to contract capacity within their LRZ in order to avoid the risk of transmission limitations and not receiving the full credit for the capacity. In the current MISO capacity construct, this capacity must be sourced from a specific generating resource capable of supplying the capacity stated in the contract. The capacity that is credited to the generating resource is also based on the individual generating resource's performance in regards to availability and reliability. Resources that operate more reliability will receive a larger percentage of its generating capability. Conversely, resources that experience significant outages are de-rated and only receive portion of their maximum output. Under this rule, generators are strongly encouraged to operate reliably in order to receive the largest portion of their capacity.

The price of capacity within MISO has been historically low and significantly below the cost of a newly constructed resource. However, with the retirement of additional coal-fired generation, market capacity has started increasing in cost and the availability of such capacity has decreased as illustrated through RPU's recent capacity contracts.

For this Study, BMcD assumed that RPU is still willing to consider purchasing bi-lateral market capacity to fulfill its resource adequacy requirements as a participant in MISO.

3.9 New Generation Resources

The capacity and energy needs of RPU are projected to potentially increase substantially over the study period. There are two approaches to satisfy the capacity and energy obligations: either from resources owned by RPU or contracted for through the market. Current EPA regulations have removed a new coal fired power plant from consideration as a new resource. Therefore, gas-fired and renewable resources are the only realistic resource options that RPU could construct. The following resources were considered within this assessment:

- Reciprocating engine plant
- Simple cycle gas turbine (SCGT) aeroderivative technology
- Simple cycle gas turbine frame technology

- Combined cycle gas turbine (CCGT) frame technology
- Combined heat and power facility
- Wind generation
- Solar generation

When owned resources were not available or economical, a contract for market capacity from an accredited resource was used to maintain reserve margins throughout the study period. Market capacity resources are modeled as temporary supply resources, expiring at the end of each year.

Table 3-2 presents a summary of the cost and performance estimates for the new resources considered within this Study for meeting RPU's future capacity and energy requirements. Further operating and cost estimate assumptions for the new resources can be found in Appendix B.

Table 3-2: New Resource Cost and Performance Summary

PROJECT TYPE	Reciprocating Engine	Aeroderivative SCGT	"F-Class" SCGT	"F-Class" CCGT	Combined Heat and Power Facility	50 MW Wind	Solar
BASE PLANT DESCRIPTION							
Number of Gas Turbines, Engines or Boilers	6	1	1	1	1	22	N/A
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	N/A	N/A
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature
PERFORMANCE							
Summer Peak Performance							
Total Net Fired Plant Output, kW	54,600	44,900	213,800	412,300	32,200	50,000	500
Total Net Fired Plant Heat Rate, Btu/kWh (HHV)	8,490	9,690	9,890	7,110	4,150	N/A	N/A
Total Net Fired Plant Heat Input, MMBtu/h (HHV)	460	440	2,110	2,930	134	N/A	N/A
Assumed Firm Capacity Credit for MISO, kW	52,000	43,000	203,000	392,000	31,000	7,000	8% of Output
CAPITAL COSTS							
Total Plant Capital Costs							
Project Cost, 2015M$ (w/o Owner's Costs)	$51	$58	$100	$314	$54	$90	$1.2
Owner's Costs 2015M$ (without Escalation and IDC)	$15	$18	$32	$60	$17	Incl. in Project Costs	Incl. in Project Costs
Total Capital Cost, 2015M$	$65	$77	$132	$374	$71	$90	$1.2
Total Capital Cost 2015$/kW Avg Annual Fired Output	$1,199	$1,712	$615	$912	$2,214	$1,804	$2,440
NON-FUEL OPERATION & MAINTENANCE COSTS							
Fixed O&M Cost, 2015$/kW-Yr	$10.97	$23.78	$7.18	$12.81	$18.60	$18.45	$11.89
Engine Major Maintenance, 2015$/Start/GT (Note 2 & 3)	N/A	N/A	$15,375	$15,375	N/A	N/A	N/A
Engine Major Maintenance, 2015$/GT-h (Note 2 & 3)	$24	$195	$410	$410	$138	N/A	N/A
Engine Major Maintenance, 2015$/MWh (Note 2 & 3)	$2.59	$4.34	$1.92	$1.29	$4.30	N/A	N/A
Variable O&M, 2015$/MWh (excl. major maintenance)	$4.51	$6.66	$0.92	$1.33	$6.66	Incl. In Fixed	Incl. In Fixed
Total Non-Fuel Variable O&M, 2015$/MWh	$7.10	$11.00	$2.84	$2.63	$10.96	N/A	N/A

Note: Further details of cost and performance estimates including the underlying assumptions are presented in Appendix B.

4.0 RESOURCE ANALYSIS & STRATEGY

RPU has a need to address several issues associated with its electric supply portfolio and resources including the following:

- Consider the addition of a new, efficient resource to limit exposure to high MISO market energy and capacity prices
- Ability to accommodate potential sharp increases in load and energy requirements due to the Destination Medical Center (DMC) and Mayo
- Position RPU for short-term and long-term compliance with environmental regulations (namely potential CO_2 regulations)
- Short-term issues associated with an aging Cascade Creek Unit 1 and potential capacity deficits
- Intermediate-term considerations with the expiration of the steam contract with Mayo in 2025
- Long-term power supply concerns with the expiration of the SMMPA PSC CROD in 2030

In order to assess options that might be beneficial to pursue with regards to these issues, BMcD developed scenarios of various resource options that RPU could follow. This part of the report provides a summary of that analysis.

Various resource planning assumptions and considerations were developed and analyzed using Ventyx's Strategist and Promod software programs to study the various futures considered viable for RPU. The Strategist model is a resource portfolio optimization model that allows an analysis of several different resources with a variety of characteristics to meet the load requirements and any other defined constraints over a finite period of time. The model develops potentially thousands of resource combinations based on the scenario-defined constraints, ranking these combinations by net present value (NPV) over the study period. This allows the selection of the lowest evaluated cost combination of resources, including optimal size and implementation schedules for new resources, based on the performance and construction costs provided. Scenarios were developed to analyze the various approaches which RPU could use to meet its obligations.

Using the results of the Strategist model, BMcD then selected several power supply futures to evaluate within Promod, an hourly dispatch commitment program that can simulate the dispatch of RPU's resources against both RPU's load and MISO market energy prices. Promod provides a granular evaluation of the anticipated operation of RPU's power supply for each hour of the year over the 20-year study period.

4.1 Power Supply Plan Model Development

In order for Strategist to optimize RPU's power supply portfolio, several assumptions were included within the model. The following provides a summary of the major assumptions included within the model:

1. The load forecast for both demand and energy was utilized for RPU based on SMMPA's planning efforts.
2. The MTEP developed forecasts for natural gas costs and market energy prices were utilized as the basis for this Study.
3. Due to its age, condition, and the potential of limited availability of spare parts, Cascade Creek Unit 1 was assumed to be retired in the event a new generator was built by RPU.
4. Renewable requirements (Appendix A provides additional information regarding the schedule of renewable generation)
   a. While CROD is in effect, most of RPU's renewable requirements will be satisfied under the SMMPA PSC.
   b. For renewable requirements over CROD, it has been assumed that RPU will contract for additional solar capacity and energy.
   c. After CROD is terminated, it has been assumed that RPU will meet the State of Minnesota's overall goal of 25 percent renewable energy with wind resource contracts and also comply with the State of Minnesota's solar requirements.
   d. Per MISO, solar and wind resources were given an 8 percent and 14 percent of nameplate capacity credit, respectively, for resource adequacy requirements.
5. For the purposes of planning, a limit of 52 MW was placed on the amount of capacity that RPU would acquire from the market through bi-later contracts before a unit would be constructed by RPU. This limit was selected as it is equal to the overall firm output of the reciprocating engine resource.
6. For the CHP option, it is assumed that fuel costs are passed through to Mayo at a typical consumption rate of a natural gas-fired boiler. Remaining fuel that is attributable to power generation was accounted for within RPU's power supply costs as well as all capital and operational costs.

4.2 Power Supply Analysis

Utilizing the assumptions described herein, BMcD developed future power supply plans utilizing the software program Strategist. After Strategist developed several power supply paths, BMcD then evaluated the paths within the hourly dispatch commitment software of Promod. Table 4-1 presents the results of the dispatch analysis.

As presented in Table 4-1, Strategist developed four unique power supply paths for RPU. Appendix C presents the detailed economic results and BLR charts for each of the four paths. Figure 4-1, Figure 4-2, Figure 4-3, and Figure 4-4 present an illustration of the total annual power supply costs, fixed costs, variable costs, and net market interactions, respectively, for each power supply path.

The following provides general observations for the power supply paths:

1. CROD expires at the end of 2030.
2. A combined cycle gas turbine facility is added in 2031.
3. Solar generation is added in 2016 at 500 kW, 2021 at 3 MW, 2028 at 3 MW, 2031 at 11.5 MW, 2033 at 0.5 MW, and 2035 at 0.5 MW.
4. Wind generation is added in 2031 at 150 MW total.
5. Each path relies on purchases of capacity from the market, though the timing and magnitude vary depending on when each new resource is added.
6. Each path retires Cascade Creek Unit 1 and adds a reciprocating engine facility and CHP facility, though the timing of the installations is varied across the cases.
7. All four paths are very close in costs illustrated with the NPV for each case within 1.2 percent.
    a. All four have fairly consistent growth rates of total power supply costs and similar costs in generation
    b. Depending on cost allocations, there is a substantial shift in fixed costs, variable costs, and net market interactions after the expiration of the SMMPA PSC CROD in 2031. Based on the cost allocation assumed herein, for all four paths starting in 2031 the fixed costs increase substantially, variable costs decrease substantially, and MISO market energy purchases increase substantially [note: most of the renewable costs have been assumed to be fixed cost components within this evaluation].

Table 4-1: Power Supply Paths and Costs

Path No.	1	2	3	4
Plan Year	**Retire CC1 2023, Install Peaker 2023**	**Retire CC1 2018, Install Peaker 2019**	**Retire CC1 2018, Install Peaker 2018**	**Retire CC1 2018, Install Peaker 2018, Install CHP 2026**
2016	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
2017				
2018		Retire CC1	Retire CC1 Peaker (50MW)	Retire CC1 Peaker (50MW)
2019		Peaker (50MW)		
2020				
2021	Solar (3MW)	Solar (3MW)	Solar (3MW)	Solar (3MW)
2022				
2023	Retire CC1 Peaker (50MW)			
2024				
2025				
2026				CHP (30MW)
2027				
2028	Solar (3MW)	Solar (3MW)	Solar (3MW)	Solar (3MW)
2029	CHP (30MW)	CHP (30MW)	CHP (30MW)	
2030				
2031	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)	Wind (150MW) CCGT (390MW) Solar (11MW)
2032				
2033	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
2034				
2035	Solar (500kW)	Solar (500kW)	Solar (500kW)	Solar (500kW)
NPV Cost ($000) *% Difference*	$1,498,056 *0.00%*	$1,506,011 *0.53%*	$1,507,624 *0.64%*	$1,515,469 *1.16%*

Figure 4-1: Total Annual Wholesale Power Supply Costs

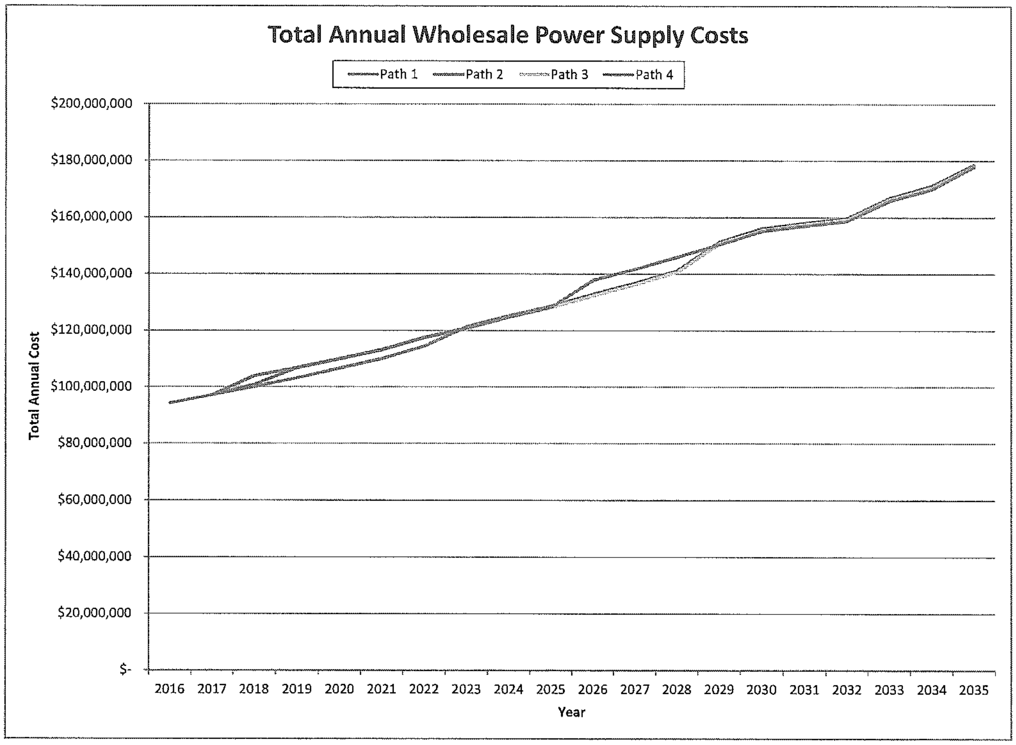


Figure 4-2: Total Fixed Costs (Fixed O&M, Debt Service & Demand Charges)

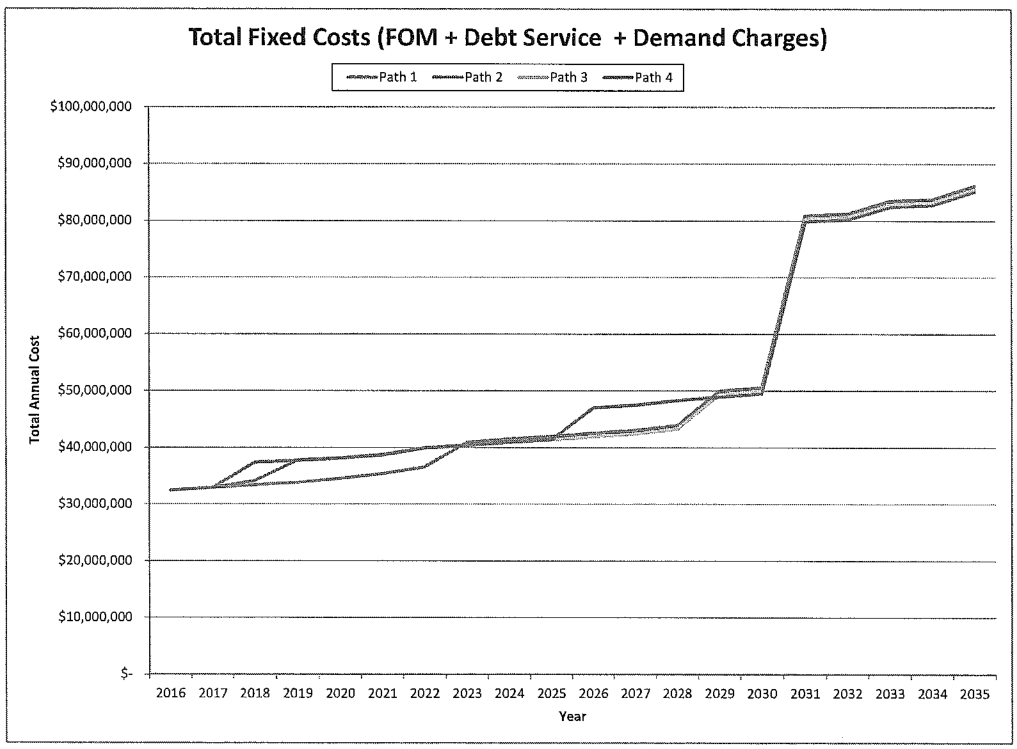


Figure 4-3: Total Variable Costs (Variable O&M & Fuel)

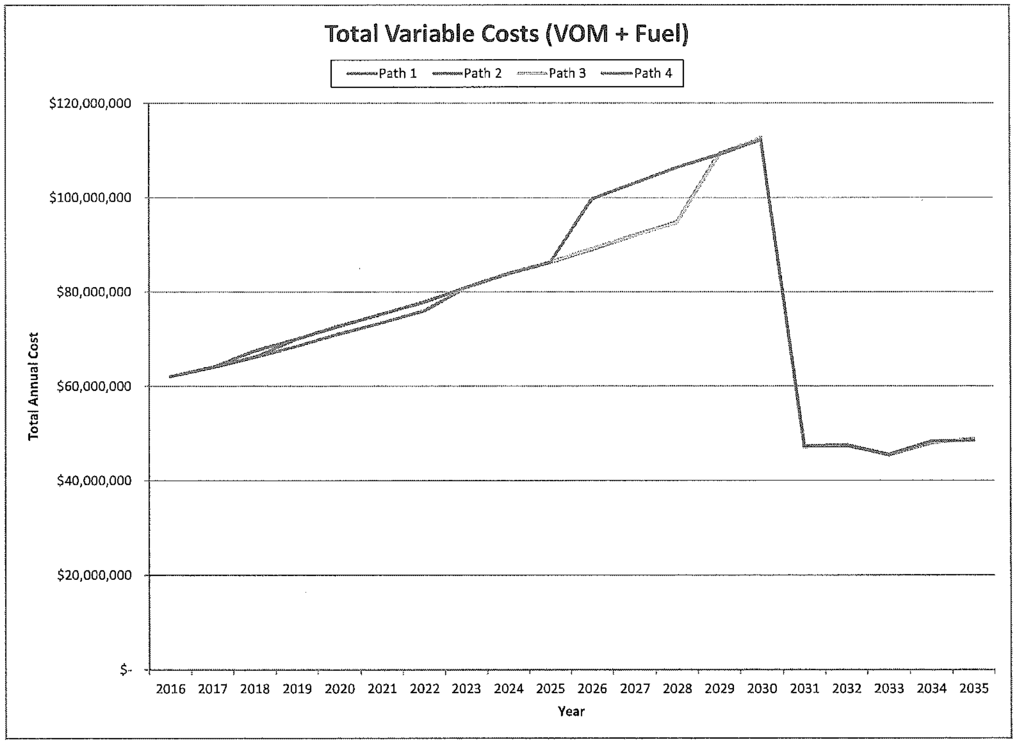
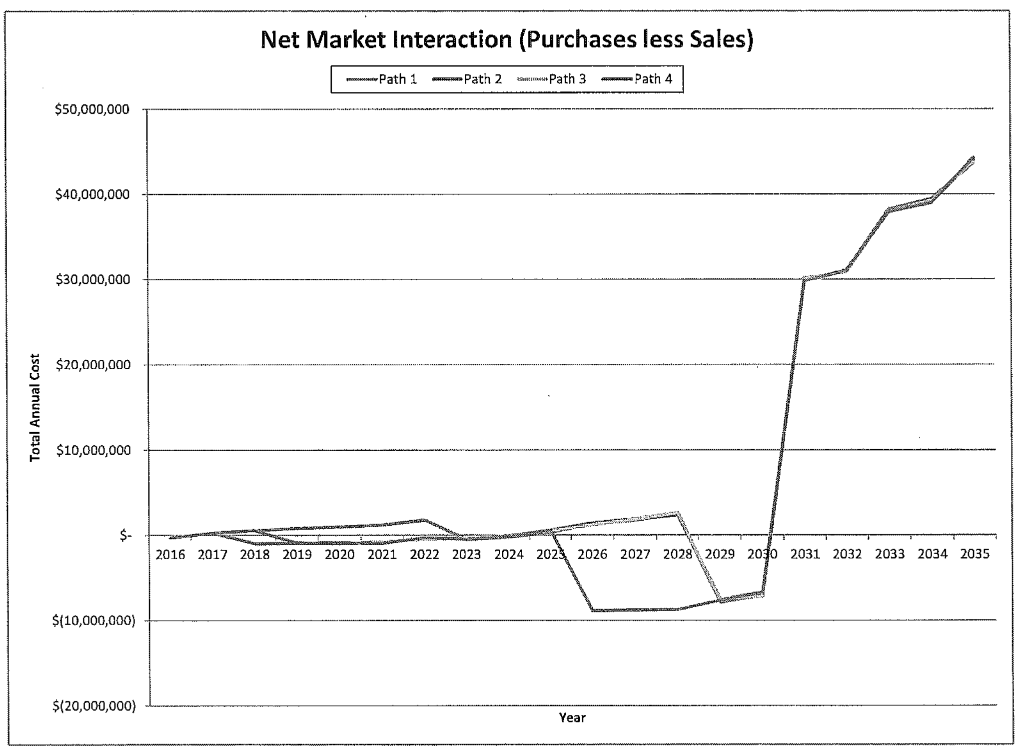


Figure 4-4: Net Market Interactions (Purchases less Sales)



4.3 Sensitivity Considerations

With any power supply plan, evaluating alternative assumptions is important to determine how the power supply path may be impacted should key assumptions vary from those in the base case. In this case, major changes within assumptions for RPU will not greatly impact the infrastructure plan moving forward. Below provides a discussion of the potential impacts that may occur due to changes within key assumptions of forecasts.

- Fluctuations in natural gas and energy prices
  - Due to EPA regulations, the only future is natural gas and renewables within RPU's power supply portfolio (though some MISO market energy will be provided by existing coal resources outside of RPU).
  - For self-build dispatchable resources, RPU will be tied to natural gas fuel regardless of the path.
  - Will not have a large impact on the path forward for RPU meeting its capacity and energy requirements. However, the magnitude of the overall power supply costs will be affected by fluctuations in natural gas and energy prices.
- Increased renewable requirement over 25 percent
  - The main driver for new resources is capacity; wind and solar generation do not provide significant capacity.
  - Increased renewables requirements will likely require "over" procuring of resources.
- Pace of load growth
  - Low load growth (or increased conservation) will avoid energy cost from CROD or MISO market, but the path forward will be relatively unchanged and will likely lead to procuring less market capacity/energy.
  - High load growth (or new load) may accelerate the need for additional capacity resources, though the specific path and resources will remain relatively unchanged, but the timing of the resources may need to be moved forward.
- CO_2 costs
  - Overall MISO market prices will be affected as MISO market energy is dependent on both coal-fired and natural gas-fired resources.
  - RPU's new resources will be compliant, efficient, and competitive within the MISO market.

5.0 SUMMARY

5.1 Summary of Key Assumptions and Conclusions

Based on the analysis presented herein, BMcD provides the following summary of assumptions and conclusions:

1. Environmental groups and agencies continue to aggressively target coal-fired plants in regards to emissions.
    a. This will lead to additional coal-fired plant retirements.
    b. Increased retirements are anticipated to reduce market capacity availability and increase MISO energy prices.
2. With the retirement of SLP from electric generation, RPU lost its "middle of the road" hedge against MISO energy prices.
3. Due to its advanced age, continued operation of Cascade Creek Unit 1 may present additional risks
    a. Facing increased maintenance costs, inefficiency, lack of OEM support, and questionable availability of spare parts
    b. Difficult to participate in MISO energy market
4. The infrastructure plans includes:
    a. Voluntary compliance with State of Minnesota renewable mandates
    b. Compliance with proposed CO_2 regulations
    c. Allows RPU to begin the transition away from joint action agency (SMMPA PSC)
    d. It may provide partnering opportunities after SMMPA PSC with other utilities
5. The infrastructure plan provides insight to several windows:
    a. Short-term: The addition of peaking resource and retirement of Cascade Creek 1 will allow RPU to maintain an appropriate amount of risk to market capacity pricing while also allowing RPU to control the retirement of Cascade Creek 1.
    b. Intermediate-term: The addition of a CHP facility appears favorable for RPU within its power supply portfolio and Mayo.
    c. Long-term: The likely replacement of SMMPA PSC is a combination of CCGT unit and renewable generation.
6. Based on the current economic and market environment, there are several considerations for earlier development of peaking resources:
    a. Interest rates are currently low

  b. The current currency exchange rate (Euro to Dollar) is favorable for reciprocating engines which are primarily priced with the Euro.
  c. Controls capacity risk exposure (controls retirement of Cascade Creek 1)
  d. The capacity market within MISO has shown decreased availability of capacity and increased cost.
  e. Provides a replacement energy-hedge with the retirement of SLP and Cascade Creek 1
  f. Protects against exposure of Cost of New Entry (CONE) pricing, which is approximately $90,000/MW-year with no benefit of energy revenue or asset investment.
7. RPU should continue to update the analysis of its future resource plans as major changes in the industry occur or as assumptions change from those used herein.

5.2 Infrastructure Plan Highlights

The following provides the overall highlights of the infrastructure plan update:

1. Positions RPU for long-term power supply with the expiration of the SMMPA Power Sales Contract (PSC) in 2030
2. Eliminates coal from the RPU portfolio by 2030 and significantly reduces carbon emissions
3. Meets renewable standards and objectives: 25 percent by 2025 renewable standard, 1.5 percent solar standard, 1.5 percent conservation standard
4. Has the flexibility to accommodate potential sharp increases or decreases in load and energy requirements due to DMC and customer solar
5. Positions RPU for short-term and long-term compliance with environmental regulations
6. Retires inefficient resource and modernizes the RPU generation fleet with high efficiency and low emission units
7. Expands partnership opportunities with the Mayo Clinic and other combined heat and power prospects

APPENDIX A – POWER SUPPLY STUDY ASSUMPTIONS

FINANCIAL ASSUMPTIONS

- Inflation/escalation rate: 2.5 percent
- Interest rate: 5.0 percent
- Financing Period: 30 years
- Discount rate for NPV calculations: 5.0 percent
- Actual 2013 hourly load shape used for system profile. This hourly load shape is then adjusted for each year to meet the peak demand and total annual energy.

GENERATION RESOURCES

Cascade Creek 1

- Gas fired combustion turbine
- Commercial operation on 6/1/1975
- 27 MW summer capacity
- 21.2 MW UCAP
- 15,112 Btu/kWh heat rate
- Fixed O&M $7.86/kW-year, 2015$, escalated at inflation
- Variable O&M $1.59/MWh, 2015$, escalated at inflation
- 21.3% forced outage rate

Cascade Creek 2

- Gas fired combustion turbine
- Commercial operation on 4/1/2002
- 49.9 MW summer capacity
- 47.4 MW UCAP
- 10,917 Btu/kWh heat rate
- Fixed O&M $4.43/kW-year, 2015$, escalated at inflation
- Variable O&M $1.59/MWh, 2015$, escalated at inflation
- 4.34% forced outage rate

IBM

- Two diesel fired combustion engines
- Commercial operation on 10/1/2005
- 3.6 MW summer capacity
- 9,589 Btu/kWh heat rate
- No variable or fixed O&M costs modeled

Lake Zumbro

- Hydroelectric plant
- Commercial operation on 11/1/1984
- 2 MW summer capacity
- Fixed O&M $19.70/kW-year, 2015$, escalated at inflation

Olmsted Waste-to-Energy Facility

- Solid waste fired steam turbine
- Commercial operation on 4/1/1987
- 2 MW summer capacity
- Variable O&M $1.06/MWh, 2015$, no escalation

SMMPA PSC CROD

- 216 MW capacity
- Contract expires after 12/31/2030

	On-Peak ($/MWh)	Off-Peak ($/MWh)	Demand ($/kW-mo)	Trans. ($/kW-mo)
2016	$55.21	$41.27	$10.66	$2.66
2017	$56.32	$42.09	$10.66	$2.66
2018	$57.44	$42.94	$10.66	$2.66
2019	$58.59	$43.80	$10.66	$2.66
2020	$59.76	$44.67	$10.66	$2.66
2021	$60.96	$45.56	$10.66	$2.66
2022	$62.18	$46.48	$10.66	$2.66
2023	$63.42	$47.41	$10.66	$2.66
2024	$64.69	$48.35	$10.66	$2.66
2025	$65.98	$49.32	$10.66	$2.66
2026	$67.30	$50.31	$10.66	$2.66
2027	$68.65	$51.31	$10.66	$2.66
2028	$70.02	$52.34	$10.66	$2.66
2029	$71.42	$53.39	$10.66	$2.66
2030	$72.85	$54.45	$10.66	$2.66

FORECASTS

RPU Demand and Energy Forecast

Year	Non-Coincident Peak (MW)	MISO Coincident Peak (MW)	Energy (GWh)
2016	297.0	289.1	1,321.3
2017	305.8	297.7	1,346.4
2018	312.8	304.5	1,372.4
2019	319.1	310.7	1,395.8
2020	324.6	316.1	1,423.3
2021	330.9	322.2	1,445.9
2022	335.3	326.6	1,472.2
2023	339.1	330.3	1,500.1
2024	342.1	333.2	1,531.4
2025	347.0	338.0	1,553.5
2026	352.2	343.2	1,582.0
2027	356.5	347.4	1,609.7
2028	360.3	351.1	1,640.9
2029	368.4	359.0	1,664.2
2030	375.1	365.6	1,691.3
2031	382.0	372.3	1,717.2
2032	388.6	378.8	1,748.0
2033	397.1	387.1	1,772.9
2034	404.3	394.2	1,804.3
2035	411.9	401.6	1,836.4

Natural Gas

Year	EIA Henry Hub ($/MMBtu, nominal)	MTEP Henry Hub ($/MMBtu, nominal)
2016	$4.41	$4.91
2017	$4.76	$5.47
2018	$5.27	$6.03
2019	$5.19	$6.43
2020	$4.96	$6.83
2021	$5.37	$7.24
2022	$5.64	$7.64
2023	$5.90	$8.04
2024	$6.20	$8.47
2025	$6.45	$8.90
2026	$6.72	$9.33
2027	$7.00	$9.76
2028	$7.26	$10.19
2029	$7.63	$10.62
2030	$8.12	$11.05
2031	$8.47	$11.48
2032	$8.91	$11.91
2033	$9.41	$12.34
2034	$9.83	$12.77
2035	$10.31	$13.20

MISO Market Energy

	MTEP Average Annual Market Prices	
Year	Off-Peak ($/MWh, nominal)	On-Peak ($/MWh, nominal)
2016	$23.70	$42.07
2017	$24.14	$43.48
2018	$24.57	$44.88
2019	$26.07	$48.31
2020	$27.57	$51.73
2021	$29.08	$55.16
2022	$30.58	$58.58
2023	$32.08	$62.01
2024	$33.02	$64.43
2025	$33.95	$66.86
2026	$34.89	$69.28
2027	$35.82	$71.71
2028	$36.76	$74.13
2029	$37.69	$76.56
2030	$38.63	$78.98
2031	$39.56	$81.41
2032	$40.50	$83.83
2033	$41.43	$86.26
2034	$42.37	$88.69
2035	$43.31	$91.11

RENEWABLE ENERGY INSTALLATION SCHEDULE

				Solar Generation Summary						Wind Generation Summary			
Year	Annual Energy Forecast (GWh)	CROD Energy (GWh)	Energy Above CROD (GWh)	Solar Requirement - Percent of Annual Energy (%)	Solar Energy Requirement (GWh)	Solar Generation Capacity Factor	Implied Solar Capacity Requirement (MW)	Solar Generation Install Schedule (MW)	Total Solar Generation Installed (MW)	Renewable Requirement - Percent of Annual Energy (%)	Renewable Energy Requirement (GWh)	Wind Capacity Factor	Implied Wind Capacity Requirement (MW)
2016	1,321	1,260	61					0.5	0.5				
2017	1,346	1,260	86						0.5				
2018	1,372	1,260	112						0.5				
2019	1,396	1,260	135						0.5				
2020	1,423	1,260	163						0.5				
2021	1,446	1,260	186	1.5%	3	18%	1.8	3	3.5				
2022	1,472	1,260	212	1.5%	3	18%	2.0		3.5				
2023	1,500	1,260	240	1.5%	4	18%	2.3		3.5				
2024	1,531	1,260	271	1.5%	4	18%	2.6		3.5				
2025	1,553	1,260	293	1.5%	4	18%	2.8		3.5				
2026	1,582	1,260	322	1.5%	5	18%	3.1		3.5				
2027	1,610	1,260	349	1.5%	5	18%	3.3		3.5				
2028	1,641	1,260	381	1.5%	6	18%	3.6	3	6.5				
2029	1,664	1,260	404	1.5%	6	18%	3.8		6.5				
2030	1,691	1,260	431	1.5%	6	18%	4.1		6.5				
2031	1,717	-	1,717	1.5%	26	18%	16.3	11.5	18	25.0%	429	33%	148.5
2032	1,748	-	1,748	1.5%	26	18%	16.6		18	25.0%	437	33%	151.2
2033	1,773	-	1,773	1.5%	27	18%	16.9		18	25.0%	443	33%	153.3
2034	1,804	-	1,804	1.5%	27	18%	17.2		18	25.0%	451	33%	156.0
2035	1,836	-	1,836	1.5%	28	18%	17.5		18	25.0%	459	33%	158.8

APPENDIX B – NEW RESOURCE TECHNOLOGY ASSESSMENT

Rochester Public Utilities
2015 Update of the RPU Infrastructure Plan
Generation Technoogy Assessment
BMcD Project No. 82902

PROJECT TYPE	Reciprocating Engine	Aeroderivative SCGT	"F-Class" SCGT	"F-Class" CCGT	Combined Heat and Power Facility	50 MW Wind	Solar
BASE PLANT DESCRIPTION							
Number of Gas Turbines, Engines or Boilers	6	1	1	1	1	22	N/A
Number of HRSGs	N/A	N/A	N/A	1	1	N/A	N/A
Number of Steam Turbines	N/A	N/A	N/A	1	N/A	N/A	N/A
Expected Service Life (years) (Note 1)	30	30	30	30	30	30	30
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	N/A	N/A
Heat Rejection	Fin-Fan Heat Ex.	Fin-Fan Heat Ex.	Fin-Fan Heat Ex.	Wet Cooling Tower	Fin-Fan Heat Ex.	N/A	N/A
NO_x Control	SCR	Water Injection	DLN	DLN/SCR	Water Injection/SCR	N/A	N/A
SO_2 Control	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	N/A	N/A
CO Control	CO Catalyst	Good Combustion Practice	Good Combustion Practice	CO Catalyst	CO Catalyst	N/A	N/A
CO_2 Control	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature
PERFORMANCE							
Summer Peak Base Load Performance (82°F, 56% RH)							
Net Plant Output, kW	54,600	44,900	213,800	317,000	32,200	50,000	500
Net Plant Heat Rate, Btu/kWh (HHV)	8,490	9,690	9,890	6,710	4,150	N/A	N/A
Heat Input, MMBtu/h (HHV)	460	440	2,110	2,130	134	N/A	N/A
Summer Peak Average Fired Performance							
Incremental Duct Firing Net Output, kW	N/A	N/A	N/A	95,300	N/A	N/A	N/A
Incremental Duct Firing Heat Rate, Btu/kWh (HHV)	N/A	N/A	N/A	8,390	N/A	N/A	N/A
Incremental Duct Firing Heat Input, MMBtu/h (HHV)	N/A	N/A	N/A	800	N/A	N/A	N/A
Total Net Fired Plant Output, kW	N/A	N/A	N/A	412,300	N/A	N/A	N/A
Total Net Fired Plant Heat Rate, Btu/kWh (HHV)	N/A	N/A	N/A	7,110	N/A	N/A	N/A
Total Net Fired Plant Heat Input, MMBtu/h (HHV)	N/A	N/A	N/A	2,930	N/A	N/A	N/A
Assumed Firm Capacity Credit for MISO Resource Adequacy, kW	52,000	43,000	203,000	392,000	31,000	7,000	8% of Output
CAPITAL COSTS							
Base Plant Capital Costs							
Project Cost, 2015M$ (w/o Owner's Costs)	$51	$58	$100	$282	$54	$90	$1.2
Owner's Costs 2015M$ (without Escalation and IDC)	$15	$18	$32	$58	$17	Incl. in Project Costs	Incl. in Project Costs
Total Capital Cost, 2015M$	$65	$77	$132	$340	$71	$90	$1.2
Total Capital Cost 2015$/kW Avg Annual Unfired Output	$1,199	$1,712	$615	$1,076	$2,214	$1,804	$2,440
Incremental Duct-Firing Capital Costs							
Project Cost, 2015M$ (w/o Owner's Costs)	N/A	N/A	N/A	$32	N/A	N/A	N/A
Owner's Costs 2015M$ (without Escalation and IDC)	N/A	N/A	N/A	$2	N/A	N/A	N/A
Total Capital Cost, 2015M$	N/A	N/A	N/A	$34	N/A	N/A	N/A
Total Capital Cost 2015$/kW Avg Annual Incremental Fired Output	N/A	N/A	N/A	$359	N/A	N/A	N/A
Total Plant Capital Costs (Base + Duct-Firing)							
Project Cost, 2015M$ (w/o Owner's Costs)	N/A	N/A	N/A	$314	N/A	N/A	N/A
Owner's Costs 2015M$ (without Escalation and IDC)	N/A	N/A	N/A	$60	N/A	N/A	N/A
Total Capital Cost, 2015M$	N/A	N/A	N/A	$374	N/A	N/A	N/A
Total Capital Cost 2015$/kW Avg Annual Fired Output	N/A	N/A	N/A	$912	N/A	N/A	N/A
NON-FUEL OPERATION & MAINTENANCE COSTS							
Fixed O&M Cost, 2015$/kW-Yr	$10.97	$23.78	$7.18	$12.81	$18.60	$18.45	$11.89
Engine Major Maintenance, 2015$/Start/GT (Note 2 & 3)	N/A	N/A	$15,375	$15,375	N/A	N/A	N/A
Engine Major Maintenance, 2015$/GT-h (Note 2 & 3)	$24	$195	$410	$410	$138	N/A	N/A
Engine Major Maintenance, 2015$/MWh (Note 2 & 3)	$2.59	$4.34	$1.92	$1.29	$4.30	N/A	N/A
Variable O&M, 2015$/MWh (excl. major maintenance)	$4.51	$6.66	$0.92	$1.33	$6.66	Incl. In Fixed	Incl. In Fixed
Total Non-Fuel Variable O&M, 2015$/MWh	$7.10	$11.00	$2.84	$2.63	$10.96	N/A	N/A
ESTIMATED EMISSIONS, ppm							
NO_X	5.0	25.0	9.0	2.0	2.5	N/A	N/A
SO_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CO	15.0	33.0	9.0	2.0	3.3	N/A	N/A
CO_2	N/A	N/A	N/A	N/A	N/A	N/A	N/A
ESTIMATED EMISSIONS, lb/MMBtu (HHV)							
NO_X	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SO_2	< 0.0051	< 0.0051	< 0.0051	< 0.0051	< 0.0051	N/A	N/A
CO	N/A	N/A	N/A	N/A	N/A	N/A	N/A
CO_2	120	120	120	120	120	N/A	N/A

NOTES

Note 1: Service life is estimated as the expected economic life. Plants may operate longer or shorter in duration, but at the end of the presented durations it may not be economically feasible to maintain the asset depending on how it has been operated and the energy market at that time.
Note 2: For GE frame units, major maintenance cost is calculated based on either individual counts of starts or operating hours. If operating hours is more than or equal to 27 hours/equivalent starts, levelized major maintenance cost in $/hr should be used to determine major maintenance cost. If operating hours/start is less than 27 hours/equivalent starts, $/start should be used to determine major maintenance cost. Both levelized major maintenance cost in $/hr and $/start represent cost for gas turbine maintenance only, including accrual for major overhaul, and does not include fuel and other variable consumptions.
Note 3: GE aero units major maintenance is based on operating hours only.

GENERAL ASSUMPTIONS

The following assumptions govern this analysis:

General
- All estimates in this table are "screening level" and are not to be guaranteed.
- Natural gas fuel is pipeline quality (.75 grains / 100 SCF sulfur)
- All emission limits are subject to the BACT process.

Capital Cost Estimates
- A multiple contract (MCC) contracting method is assumed for this project.
- All capital cost estimates exclude escalation and are reflective of 2015$.
- Plant capital cost ($/kW) is based on the net output at summer conditions (82°F, 56% RH).
- The plant site is a greenfield site that is clear of trees and wetlands and is reasonably level. There are no existing structures or underground utilities.
- Sufficient laydown area is available.
- Piling is included under heavily loaded foundations.
- All options include a full enclosure, generation building, warehouse, control room, and other typical buildings.
- The LM6000 option includes natural gas compressors. All other options assume gas is available at proper pressure at the site boundary.

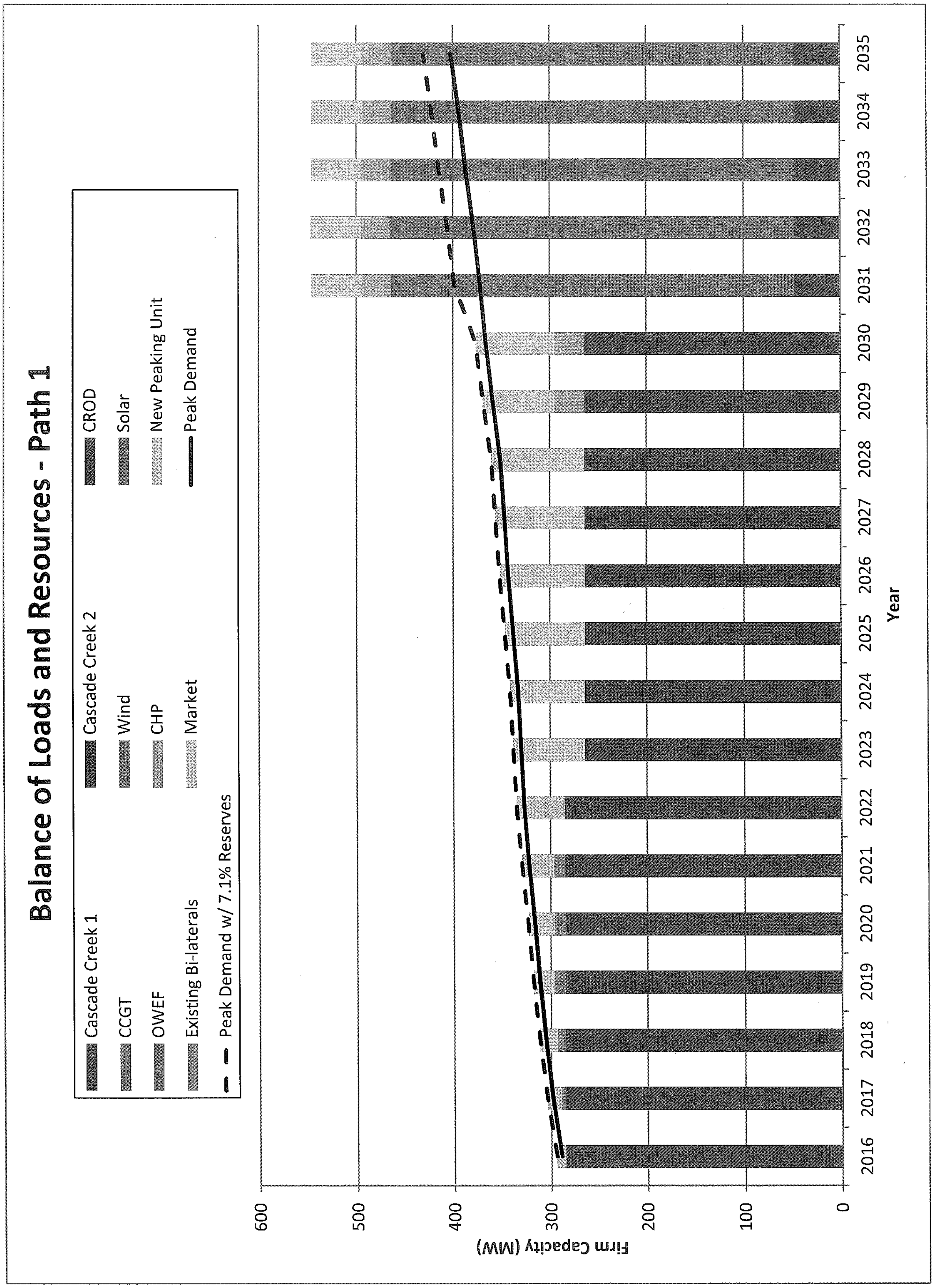
Owner's Cost
- Owner's costs include project development, operations personnel prior to COD, startup management, construction power, legal costs, permitting and licensing fees, site security, operating spare parts, permanent plant furnishings and equipment,water and natural gas infrastructure/supply, sales tax and duties, and 5% owners contingency.
- Owner's costs do not include emissions reduction credits, land, water rights, financing fees, escalation or AFUDC.

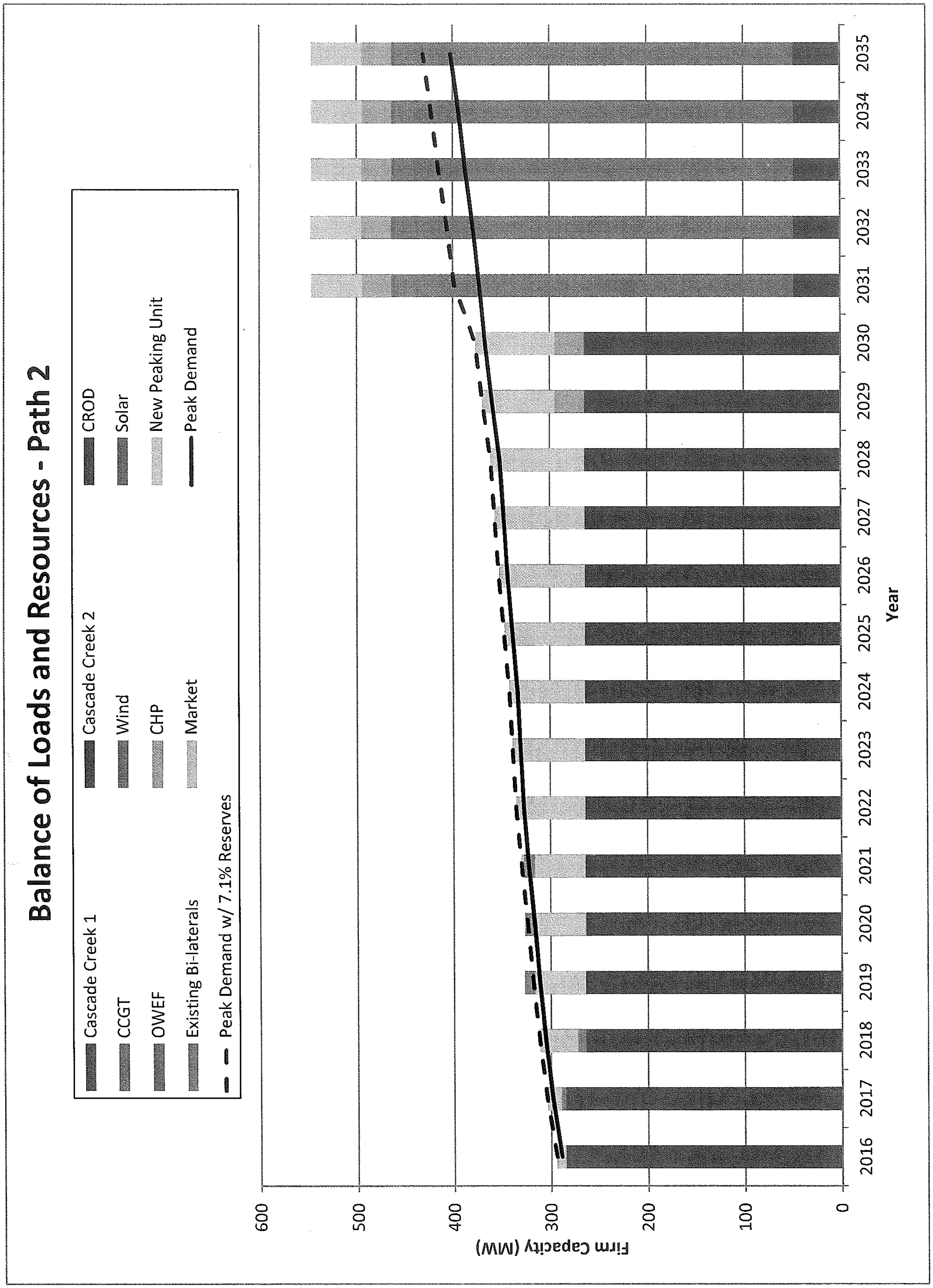
Tie-Ins
- On site wells and pipe are included in the owner's costs for raw water supply.
- An on-site switchyard is included in the Owner's costs for all options. Transmission interconnect and lines from the site have been excluded.
- A 5-mile natural gas pipeline is included in the owner's costs.

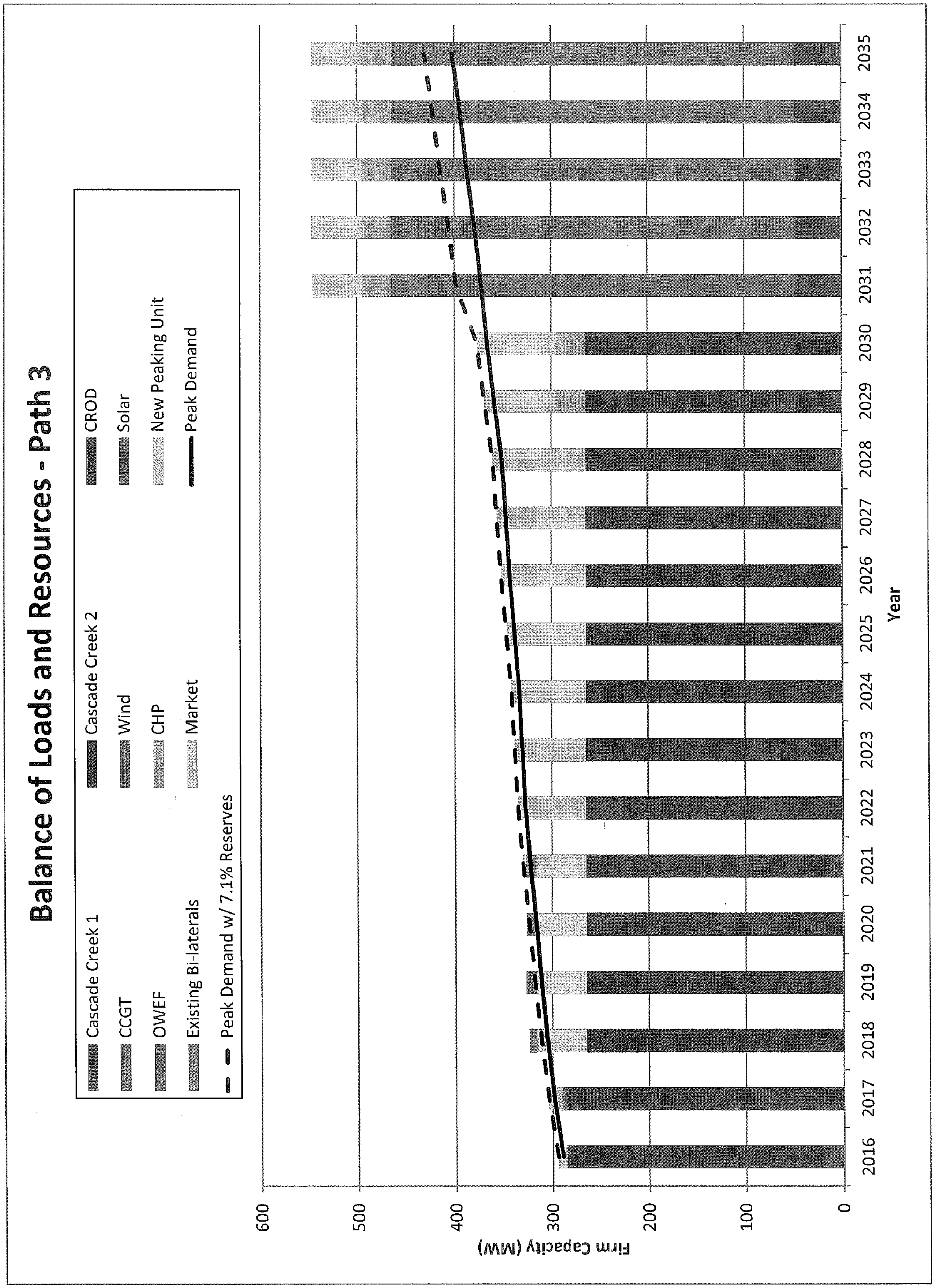
Performance Estimates
- Output and heat rate estimates are at new & clean conditions.
- Performance estimates provided are based on summer conditions (82°F, 56% RH).
- Evaporative cooling is included for the gas turbine options and operates above ambient conditions of 59°F.
- Combined cycle option is fully fired to a duct burner temperature of 1,600F.

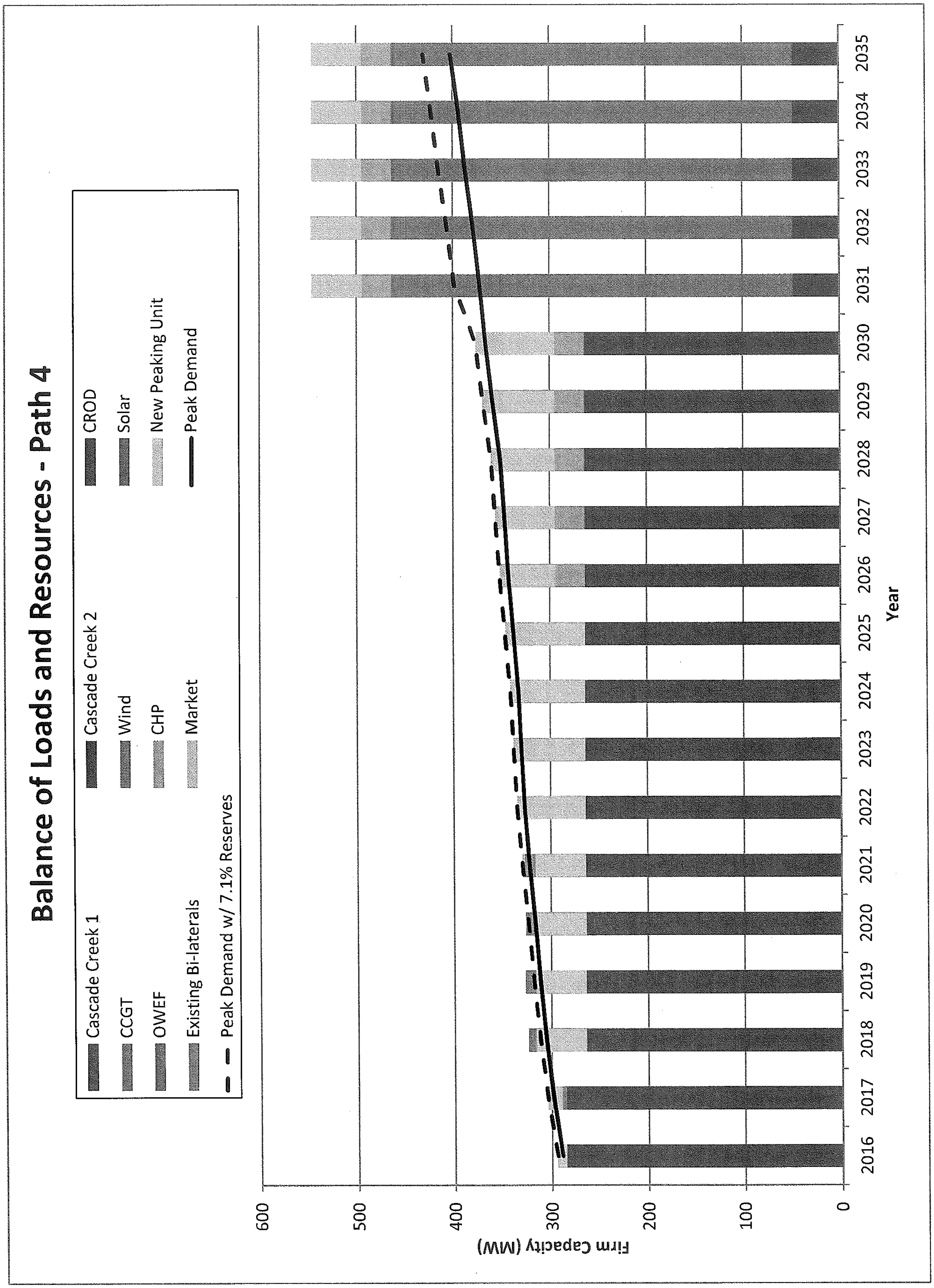
O&M Estimates are based on the following assumptions:
- Fuel costs are not included in the O&M analysis.
- Demineralized and raw water production and treatment costs are included in the variable O&M analysis. Water treatment equipment is included in the capital cost.
- Simple cycle options assume demin trailers (where applicable), while the combined cycle option assumes an on site demineralized water system.
- O&M Costs do not include emissions allowances.
- Fixed O&M includes staffing costs, major maintenance service director fee, standby power, and other office and administration cost.
- Variable O&M includes raw water, consumables, and other O&M such as BOP equipment maintenance and startup cost.

APPENDIX C – DISPATCH MODEL RESULTS


Balance of Loads and Resources - Path 1
Cascade Creek 1
Cascade Creek 2
CROD
CCGT
Wind
Solar
OWEF
CHP
New Peaking Unit
Existing Bi-laterals
Market
Peak Demand
Peak Demand w/ 7.1% Reserves
Firm Capacity (MW)
0
100
200
300
400
500
600
Year
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035


Balance of Loads and Resources - Path 2
Cascade Creek 1
Cascade Creek 2
CROD
CCGT
Wind
Solar
OWEF
CHP
New Peaking Unit
Existing Bi-laterals
Market
Peak Demand
Peak Demand w/ 7.1% Reserves
Firm Capacity (MW)
0
100
200
300
400
500
600
Year
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035


Balance of Loads and Resources - Path 3
Cascade Creek 1
Cascade Creek 2
CROD
CCGT
Wind
Solar
OWEF
CHP
New Peaking Unit
Existing Bi-laterals
Market
Peak Demand
Peak Demand w/ 7.1% Reserves
Firm Capacity (MW)
0
100
200
300
400
500
600
Year
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035


Balance of Loads and Resources - Path 4
Cascade Creek 1
Cascade Creek 2
CROD
CCGT
Wind
Solar
OWEF
CHP
New Peaking Unit
Existing Bi-laterals
Market
Peak Demand
Peak Demand w/ 7.1% Reserves
Firm Capacity (MW)
0
100
200
300
400
500
600
Year
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035

Rochester Public Utilities
2015 Update of the RPU Infrastructure Study
Project No. 82902
Summary of Results

Promod Modeling Results

Path No.	1	2	3	4
Plan Year	**Retire CC1 2023, Install Recip 2023**	**Retire CC1 2018, Install Recip 2019**	**Retire CC1 2018, Install Recip 2018**	**Retire CC1 2018, Install Recip 2018, Install CHP 2026**
2016	SOLR(1) DEF(9)	SOLR(1) DEF(9)	SOLR(1) DEF(9)	SOLR(1) DEF(9)
2017	DEF(19)	DEF(19)	DEF(19)	DEF(19)
2018	DEF(26)	RCC1(1) DEF(48)	RCC1(1) RENG(1)	RCC1(1) RENG(1)
2019	DEF(33)	RENG(1) DEF(2)	DEF(2)	DEF(2)
2020	DEF(38)	DEF(7)	DEF(7)	DEF(7)
2021	SOLR(6) DEF(44)	SOLR(6) DEF(13)	SOLR(6) DEF(13)	SOLR(6) DEF(13)
2022	DEF(50)	DEF(19)	DEF(19)	DEF(19)
2023	RENG(1) RCC1(1) DEF(22)	DEF(22)	DEF(22)	DEF(22)
2024	DEF(25)	DEF(25)	DEF(25)	DEF(25)
2025	DEF(31)	DEF(31)	DEF(31)	DEF(31)
2026	DEF(36)	DEF(36)	DEF(36)	CHP(1) DEF(5)
2027	DEF(40)	DEF(40)	DEF(40)	DEF(40)
2028	SOLR(6) DEF(44)	SOLR(6) DEF(44)	SOLR(6) DEF(44)	SOLR(6) DEF(14)
2029	CHP(1) DEF(22)	CHP(1) DEF(22)	CHP(1) DEF(22)	DEF(22)
2030	DEF(30)	DEF(30)	DEF(30)	DEF(30)
2031	WIND(3) CCGT(1) SOLR(23)	WIND(3) CCGT(1) SOLR(23)	WIND(3) CCGT(1) SOLR(23)	WIND(3) CCGT(1) SOLR(23)
2032				
2033	SOLR(1)	SOLR(1)	SOLR(1)	SOLR(1)
2034				
2035	SOLR(1)	SOLR(1)	SOLR(1)	SOLR(1)
NPV UTILITY COST (@ 5.0%) PLANNING PERIOD ($000) *% DIFFERENCE*	With CROD $1,498,056 *0.00%*	With CROD $1,506,011 *0.53%*	With CROD $1,507,624 *0.64%*	With CROD $1,515,469 *1.16%*

Notes
The number in parenthesis represents the number of units added in that particular year.
SOLR: Solar generation resource
DEF: Market capacity with a unit output of 1 MW
RCC1: Retirement of Cascade Creek Unit 1
RENG: New peaking unit (reciprocating engine facility is representative technology)
CHP: Combined heat and power facility
WIND: Wind generation resource
CCGT: Combined cycle gas turbine facility

Rochester Public Utilities
2016 Update of the RPU Infrastructure Study
Project No. 82902
Path 1: Retire CC1 2023, peaking resource added in 2023, CHP added in 2029

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Annual Energy Requirements (MWh)	1,321,296	1,346,402	1,372,397	1,395,798	1,423,297	1,445,898	1,472,201	1,500,100	1,531,394	1,553,500
Market Energy										
Market Energy Purchases (MWh)	23,583	25,663	26,331	31,408	33,981	41,200	51,301	52,454	55,631	62,315
Market Energy Purchases Cost ($)	$ 1,059,558	$ 1,260,757	$ 1,302,044	$ 1,749,565	$ 2,029,511	$ 2,533,735	$ 3,126,625	$ 3,480,470	$ 3,683,499	$ 4,415,727
Average Market Energy Purchase Cost ($/MWh)	$ 44.93	$ 49.13	$ 52.87	$ 55.70	$ 59.72	$ 61.50	$ 60.95	$ 66.54	$ 69.81	$ 70.86
Market Energy Sales (MWh)	24,528	19,529	17,110	17,458	17,950	22,519	21,988	47,135	48,737	44,730
Market Energy Sales Revenue ($)	$ 1,318,762	$ 998,988	$ 844,014	$ 938,775	$ 1,051,991	$ 1,329,404	$ 1,317,305	$ 3,998,235	$ 4,124,908	$ 4,069,759
Average Market Energy Sales Revenue ($/MWh)	$ 53.76	$ 51.15	$ 49.33	$ 53.77	$ 58.61	$ 59.03	$ 59.91	$ 84.82	$ 86.26	$ 90.99
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 39.72	$ 41.02	$ 42.28	$ 45.38	$ 48.58	$ 51.75	$ 55.00	$ 58.18	$ 60.29	$ 62.50
LMP Off-Peak Average ($/MWh)	$ 24.37	$ 24.82	$ 25.30	$ 26.99	$ 28.53	$ 30.12	$ 31.81	$ 33.16	$ 34.33	$ 35.29
Market Capacity										
Market Capacity Purchase (MW)	9	15	18	22	27	33	50	22	25	31
Market Capacity Cost ($/kW-mo)	$ 4.00	$ 4.08	$ 4.16	$ 4.24	$ 4.33	$ 4.42	$ 4.50	$ 4.59	$ 4.69	$ 4.78
Total Market Capacity Cost ($)	$ 439,429	$ 724,403	$ 913,522	$ 1,108,367	$ 1,406,845	$ 1,763,156	$ 2,680,285	$ 1,207,732	$ 1,413,017	$ 1,749,641
Unit Operating Capacity (MW)										
CC1	27	27	27	27	27	27	27	27	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	-	-	-	-	55	55	55
CROD OFF	216	216	216	216	216	216	216	216	216	216
CROD On	216	216	216	216	216	216	216	216	216	216
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	1	1	1	1	1	4	4	4	4	4
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
Number of Starts										
CC1	3	2	1	1	1	-	2	-	-	-
CC2	37	23	15	16	18	17	16	19	17	16
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	-	-	-	-	117	123	114
Unit Generation (MWh)										
CC1	432	270	122	122	122	-	270	-	-	-
CC2	11,277	6,462	4,192	4,541	5,015	4,840	4,017	5,439	4,915	4,516
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	-	-	-	-	23,091	24,101	22,599
CROD OFF	760,826	773,391	786,501	798,348	812,728	823,617	836,952	860,659	866,233	876,518
CROD On	542,200	550,225	558,539	566,042	575,009	581,837	589,626	598,046	607,213	613,160
LZ	11,523	11,504	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504
OWEF (PPA)	479	479	479	479	479	479	479	479	479	479
SOLAR (PPA)	817	814	814	814	818	5,696	5,718	5,722	5,725	5,722
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
RPU Generation Subtotal (MWh)	23,233	18,236	15,818	16,167	16,654	16,345	15,791	40,935	40,534	38,529
CROD Subtotal (MWh)	1,303,026	1,323,588	1,345,240	1,364,390	1,387,738	1,405,654	1,426,778	1,448,705	1,473,447	1,489,677
PPA Purchase Subtotal (MWh)	1,296	1,293	1,293	1,293	1,298	6,174	6,197	6,201	6,204	6,201
Total Unit Generation (MWh)	1,327,555	1,343,115	1,362,350	1,381,849	1,405,689	1,428,173	1,448,766	1,495,846	1,520,184	1,534,407
Capacity Factor										
CC1	0.2%	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.0%		
CC2	2.6%	1.5%	1.0%	1.0%	1.1%	1.1%	0.9%	1.2%	1.1%	1.0%
CCGT										
CHP										
RENG								5.0%	5.0%	4.7%
Fuel Cost ($)										
CC1	$ 36,965	$ 25,763	$ 12,785	$ 13,637	$ 14,588	$ -	$ 35,088	$ -	$ -	$ -
CC2	$ 709,888	$ 453,167	$ 320,464	$ 370,121	$ 435,978	$ 444,773	$ 390,927	$ 556,795	$ 527,296	$ 511,760
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,924,846	$ 2,042,340	$ 2,003,099
Total Fuel Costs ($)	$ 746,853	$ 478,930	$ 333,249	$ 383,758	$ 450,526	$ 444,773	$ 426,015	$ 2,481,642	$ 2,569,637	$ 2,514,860
Variable O&M ($)										
CC1	$ 714	$ 448	$ 207	$ 211	$ 217	$ -	$ 508	$ -	$ -	$ -
CC2	$ 18,540	$ 10,727	$ 7,126	$ 7,901	$ 8,977	$ 8,858	$ 7,552	$ 10,497	$ 9,063	$ 9,122
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 207,636	$ 213,801	$ 204,669
CROD OFF	$ 31,398,662	$ 32,554,308	$ 33,773,894	$ 34,963,812	$ 36,305,470	$ 37,536,838	$ 38,898,029	$ 40,325,764	$ 41,685,356	$ 43,230,295
CROD On	$ 29,936,285	$ 30,986,936	$ 32,089,981	$ 33,165,541	$ 34,384,802	$ 35,468,276	$ 36,674,429	$ 37,929,244	$ 39,280,854	$ 40,458,621
Total Variable O&M Costs ($)	$ 61,354,212	$ 63,552,418	$ 65,871,208	$ 68,137,466	$ 70,679,455	$ 73,013,972	$ 75,580,518	$ 78,473,141	$ 81,389,694	$ 83,902,907
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1	$ 87.27	$ 97.08	$ 106.93	$ 113.98	$ 121.83		$ 135.17			
CC2	$ 64.59	$ 71.79	$ 78.15	$ 83.25	$ 88.72	$ 93.72	$ 99.17	$ 104.30	$ 100.25	$ 115.34
CCGT										
CHP										
RENG								$ 88.89	$ 93.61	$ 98.08
CROD OFF	$ 41.27	$ 42.09	$ 42.94	$ 43.80	$ 44.67	$ 45.56	$ 46.48	$ 47.41	$ 48.35	$ 49.32
CROD On	$ 55.21	$ 56.32	$ 57.44	$ 58.59	$ 59.76	$ 60.96	$ 62.18	$ 63.42	$ 64.69	$ 65.98
Fixed O&M ($)										
CC1	$ 314,199	$ 317,520	$ 325,620	$ 333,720	$ 342,090	$ 350,460	$ 359,370	$ -	$ -	$ -
CC2	$ 226,610	$ 229,041	$ 234,530	$ 240,518	$ 246,506	$ 252,993	$ 258,981	$ 265,468	$ 272,454	$ 278,941
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 729,777	$ 748,021	$ 766,722
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 31,325,795	$ 31,520,589	$ 31,792,666	$ 32,034,918	$ 32,399,314	$ 32,563,198	$ 32,837,514	$ 33,092,167	$ 33,448,484	$ 33,536,200
LZ	$ 52,338	$ 53,219	$ 54,296	$ 55,373	$ 56,668	$ 57,632	$ 58,762	$ 59,944	$ 61,320	$ 62,387
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 5,946	$ 6,060	$ 6,208	$ 6,366	$ 6,986	$ 46,778	$ 47,087	$ 49,206	$ 50,694	$ 51,698
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Fixed O&M Costs ($)	$ 31,924,888	$ 32,126,430	$ 32,413,321	$ 32,670,895	$ 33,051,564	$ 33,271,059	$ 33,562,614	$ 34,196,562	$ 34,578,983	$ 34,696,044
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,199,381	$ 5,199,381	$ 5,199,381
SOLAR (PPA)	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 343,604	$ 343,604	$ 343,604	$ 343,604	$ 343,604
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Payment	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 343,604	$ 343,604	$ 5,542,985	$ 5,542,985	$ 5,542,985
Total Variable ($, VOM + Fuel)	$ 62,101,065	$ 64,031,349	$ 66,204,457	$ 68,521,224	$ 71,129,992	$ 73,458,745	$ 76,007,333	$ 80,954,783	$ 83,959,330	$ 86,417,767
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 32,443,679	$ 32,930,186	$ 33,406,206	$ 33,856,625	$ 34,537,772	$ 35,377,819	$ 36,586,502	$ 40,947,279	$ 41,534,985	$ 41,988,670
Net Market Purchases (Sales) ($, Purchases less Sales)	$ (259,203)	$ 261,769	$ 548,030	$ 810,791	$ 977,520	$ 1,204,331	$ 1,809,320	$ (507,765)	$ (241,409)	$ 345,968
Total Power Supply Cost ($)	$ 94,285,541	$ 97,223,314	$ 100,158,694	$ 103,188,640	$ 106,645,285	$ 110,040,895	$ 114,403,155	$ 121,394,207	$ 125,252,806	$ 128,752,405
Total Power Supply Cost ($/MWh)	$ 71.36	$ 72.21	$ 72.98	$ 73.93	$ 74.93	$ 76.11	$ 77.71	$ 80.92	$ 81.79	$ 82.88

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Requirements (MWh)	1,582,000	1,609,687	1,640,901	1,664,201	1,691,300	1,717,197	1,748,004	1,772,901	1,804,300	1,836,400
Market Energy										
Market Energy Purchases (MWh)	70,795	78,594	85,667	97,949	111,114	1,717,197	1,744,025	1,772,901	1,804,300	1,836,400
Market Energy Purchases Cost ($)	$ 5,133,172	$ 5,814,662	$ 6,471,221	$ 7,563,607	$ 8,759,055	$ 110,242,103	$ 115,122,250	$ 120,082,732	$ 125,464,083	$ 131,180,376
Average Market Energy Purchase Cost ($/MWh)	$ 72.51	$ 73.98	$ 75.54	$ 77.22	$ 78.83	$ 64.20	$ 66.01	$ 67.73	$ 69.54	$ 71.43
Market Energy Sales (MWh)	41,251	41,461	42,548	218,180	216,654	1,024,075	1,011,405	978,518	968,294	985,884
Market Energy Sales Revenue ($)	$ 3,787,303	$ 4,028,592	$ 3,989,341	$ 15,445,589	$ 15,778,212	$ 80,376,603	$ 84,155,375	$ 81,832,416	$ 85,979,915	$ 87,538,207
Average Market Energy Sales Revenue ($/MWh)	$ 91.81	$ 97.17	$ 93.76	$ 70.79	$ 72.83	$ 78.49	$ 83.21	$ 83.63	$ 87.00	$ 88.79
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 64.78	$ 67.01	$ 69.04	$ 71.55	$ 73.62	$ 75.85	$ 78.16	$ 80.49	$ 82.73	$ 84.93
LMP Off-Peak Average ($/MWh)	$ 36.28	$ 37.29	$ 38.14	$ 39.17	$ 40.37	$ 41.30	$ 42.30	$ 43.15	$ 44.14	$ 45.15
Market Capacity										
Market Capacity Purchase (MW)	36	40	44	22	30	-	-	-	-	-
Market Capacity Cost ($/kW-mo)	$ 4.88	$ 4.97	$ 5.07	$ 5.17	$ 5.28	$ 5.38	$ 5.49	$ 5.60	$ 5.71	$ 5.83
Total Market Capacity Cost ($)	$ 2,097,753	$ 2,395,555	$ 2,686,915	$ 1,373,243	$ 1,876,435	$ -	$ -	$ -	$ -	$ -
Unit Operating Capacity (MW)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	317	317	317	317	317
CHP	-	-	-	32	32	32	32	32	32	32
RENG	55	55	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	-	-	-	-	-
CROD On	216	216	216	216	216	-	-	-	-	-
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	4	4	7	7	7	10	18	21	21	24
WIND (PPA)	-	-	-	-	-	150	150	150	150	150
Number of Starts										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	13	13	9	10	11	12	11	10	11	11
CCGT	-	-	-	-	-	122	122	114	116	112
CHP	-	-	-	13	19	14	15	16	9	17
RENG	108	104	90	95	94	95	97	83	77	84
Unit Generation (MWh)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	3,340	3,643	2,720	2,694	2,944	3,169	3,019	2,869	3,069	2,919
CCGT	-	-	-	-	-	340,767	339,193	295,258	306,460	296,177
CHP	-	-	-	176,311	175,538	175,941	174,694	173,349	173,284	172,731
RENG	20,300	20,093	17,184	17,294	16,470	16,141	14,494	13,176	11,529	14,274
CROD OFF	890,213	902,920	917,001	925,346	935,701	-	-	-	-	-
CROD On	620,908	627,880	635,225	639,430	644,485	-	-	-	-	-
LZ	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504	11,501	11,504
OWEF (PPA)	479	479	479	479	479	18,379	18,441	18,382	18,362	18,382
SOLAR (PPA)	5,722	5,742	10,649	10,650	10,630	39,257	29,445	31,398	34,325	39,137
WIND (PPA)	-	-	-	-	-	429,765	431,269	430,573	430,573	430,573
RPU Generation Subtotal (MWh)	35,051	35,241	31,421	209,023	206,457	547,552	533,068	495,156	505,866	498,925
CROD Subtotal (MWh)	1,511,121	1,530,779	1,552,226	1,564,777	1,580,185	-	-	-	-	-
PPA Purchase Subtotal (MWh)	6,201	6,221	11,127	11,078	11,098	477,441	479,154	480,294	483,261	489,892
Total Unit Generation (MWh)	1,552,372	1,572,240	1,594,774	1,783,858	1,797,740	1,024,993	1,012,242	979,418	989,147	988,718
Capacity Factor										
CC1										
CC2	0.8%	0.8%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
CCGT						12.3%	11.9%	10.6%	11.0%	10.7%
CHP				62.5%	62.2%	62.4%	62.0%	61.5%	61.4%	61.6%
RENG	4.2%	4.2%	3.5%	3.6%	3.4%	3.4%	3.0%	2.7%	2.4%	3.0%
Fuel Cost ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 396,132	$ 449,529	$ 349,257	$ 389,410	$ 412,275	$ 459,097	$ 454,797	$ 446,256	$ 403,961	$ 485,566
CCGT	$ -	$ -	$ -	$ -	$ -	$ 30,814,384	$ 30,824,475	$ 28,528,309	$ 30,771,022	$ 30,816,946
CHP	$ -	$ -	$ -	$ 9,137,309	$ 9,459,817	$ 9,848,592	$ 10,150,009	$ 10,421,775	$ 10,790,053	$ 11,172,540
RENG	$ 1,886,327	$ 1,966,327	$ 1,751,071	$ 1,837,897	$ 1,824,083	$ 1,858,811	$ 1,732,760	$ 1,632,721	$ 1,464,160	$ 1,887,279
Total Fuel Costs ($)	$ 2,282,459	$ 2,415,855	$ 2,100,328	$ 11,364,616	$ 11,696,185	$ 42,981,764	$ 43,152,041	$ 41,029,064	$ 43,539,217	$ 44,362,431
Variable O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 6,921	$ 7,759	$ 5,929	$ 6,454	$ 6,742	$ 7,446	$ 7,245	$ 7,087	$ 7,764	$ 7,561
CCGT	$ -	$ -	$ -	$ -	$ -	$ 1,327,520	$ 1,314,259	$ 1,208,355	$ 1,285,638	$ 1,273,479
CHP	$ -	$ -	$ -	$ 2,729,701	$ 2,785,680	$ 2,861,869	$ 2,915,968	$ 2,952,453	$ 3,035,387	$ 3,119,654
RENG	$ 188,295	$ 191,954	$ 168,261	$ 173,570	$ 169,437	$ 170,200	$ 156,653	$ 145,972	$ 130,919	$ 166,142
CROD OFF	$ 44,783,891	$ 46,331,575	$ 47,995,210	$ 49,400,630	$ 50,952,483	$ -	$ -	$ -	$ -	$ -
CROD On	$ 41,789,480	$ 43,102,515	$ 44,480,296	$ 45,670,288	$ 46,951,916	$ -	$ -	$ -	$ -	$ -
Total Variable O&M Costs ($)	$ 86,768,588	$ 89,833,804	$ 92,649,696	$ 97,980,640	$ 100,866,258	$ 4,367,037	$ 4,394,126	$ 4,323,867	$ 4,459,708	$ 4,566,836
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1										
CC2	$ 120.56	$ 125.54	$ 130.60	$ 136.78	$ 142.32	$ 147.52	$ 153.05	$ 158.00	$ 163.49	$ 168.96
CCGT						$ 94.31	$ 97.64	$ 100.71	$ 104.60	$ 108.35
CHP				$ 67.31	$ 69.78	$ 72.24	$ 74.71	$ 77.21	$ 79.78	$ 82.26
RENG	$ 102.89	$ 107.41	$ 111.69	$ 116.31	$ 121.04	$ 125.71	$ 130.38	$ 134.89	$ 140.09	$ 143.88
CROD OFF	$ 50.31	$ 51.31	$ 52.34	$ 53.39	$ 54.45					
CROD On	$ 67.30	$ 68.65	$ 70.02	$ 71.42	$ 72.85					
Fixed O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 285,927	$ 293,412	$ 300,398	$ 307,883	$ 315,867	$ 323,851	$ 331,835	$ 339,819	$ 348,302	$ 357,284
CCGT	$ -	$ -	$ -	$ -	$ -	$ 6,028,236	$ 6,178,942	$ 6,333,415	$ 6,491,751	$ 6,654,044
CHP	$ -	$ -	$ -	$ 846,258	$ 867,415	$ 889,100	$ 911,328	$ 934,111	$ 957,464	$ 981,400
RENG	$ 785,800	$ 805,537	$ 825,676	$ 846,318	$ 867,476	$ 889,162	$ 911,302	$ 934,176	$ 957,531	$ 981,469
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 33,718,273	$ 33,881,554	$ 34,086,336	$ 34,060,265	$ 34,078,584	$ -	$ -	$ -	$ -	$ -
LZ	$ 63,522	$ 64,809	$ 66,351	$ 67,509	$ 68,849	$ 70,241	$ 71,658	$ 73,078	$ 74,549	$ 76,020
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 52,939	$ 54,911	$ 103,945	$ 105,907	$ 109,678	$ 308,203	$ 318,166	$ 378,035	$ 387,362	$ 453,820
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 3,856,985	$ 3,974,434	$ 4,052,583	$ 4,152,736	$ 4,256,038
Total Fixed O&M Costs ($)	$ 34,906,651	$ 35,100,322	$ 35,382,706	$ 36,234,139	$ 36,307,869	$ 12,365,779	$ 12,697,952	$ 13,045,217	$ 13,369,714	$ 13,760,075
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ 32,862,506	$ 32,862,508	$ 32,862,506	$ 32,862,506	$ 32,862,506
CHP	$ -	$ -	$ -	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864
RENG	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381	$ 5,199,381
SOLAR (PPA)	$ 343,604	$ 343,604	$ 636,870	$ 636,870	$ 636,870	$ 1,812,410	$ 1,812,410	$ 3,707,998	$ 3,707,998	$ 5,660,881
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919
Total Payment	$ 5,542,985	$ 5,542,985	$ 5,836,251	$ 12,384,118	$ 12,384,116	$ 68,542,080	$ 68,542,080	$ 70,437,668	$ 70,437,668	$ 72,390,551
Total Variable ($, VOM + Fuel)	$ 89,051,047	$ 92,049,659	$ 94,750,024	$ 109,345,257	$ 112,562,443	$ 47,348,801	$ 47,556,167	$ 45,352,931	$ 47,998,925	$ 48,929,267
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 42,547,389	$ 43,038,862	$ 43,905,872	$ 49,991,496	$ 50,568,419	$ 80,907,859	$ 81,240,032	$ 83,482,885	$ 83,607,383	$ 86,150,626
Net Market Purchases (Sales) ($, Purchases less Sales)	$ 1,345,869	$ 1,786,070	$ 2,481,880	$ (7,881,983)	$ (7,019,157)	$ 29,865,501	$ 30,966,875	$ 38,250,315	$ 39,484,168	$ 43,642,170
Total Power Supply Cost ($)	$ 132,944,305	$ 136,874,591	$ 141,137,777	$ 151,454,772	$ 156,111,705	$ 158,122,160	$ 159,763,073	$ 167,086,131	$ 171,290,475	$ 178,722,082
Total Power Supply Cost ($/MWh)	$ 84.04	$ 85.03	$ 86.01	$ 91.01	$ 92.30	$ 92.08	$ 91.40	$ 94.24	$ 94.93	$ 97.32

Net Present Cost ($) $ 1,488,055,997

Rochester Public Utilities
2015 Update of the RPU Infrastructure Study
Project No. 82902
Path 2: Retire CC1 2016, peaking resource added in 2019, CHP added in 2029

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Annual Energy Requirements (MWh)	1,321,296	1,346,402	1,372,397	1,395,799	1,423,297	1,445,888	1,472,201	1,500,100	1,531,394	1,553,500
Market Energy										
Market Energy Purchases (MWh)	23,583	25,683	26,331	31,408	33,981	41,200	51,301	52,454	55,631	62,315
Market Energy Purchases Cost ($)	$ 1,059,558	$ 1,260,757	$ 1,392,044	$ 1,749,565	$ 2,029,511	$ 2,533,735	$ 3,126,625	$ 3,490,470	$ 3,883,489	$ 4,415,727
Average Market Energy Purchase Cost ($/MWh)	$ 44.93	$ 49.13	$ 52.87	$ 55.70	$ 59.72	$ 61.50	$ 60.95	$ 66.54	$ 69.81	$ 70.86
Market Energy Sales (MWh)	24,528	19,529	16,989	38,584	39,185	45,906	43,678	47,135	45,530	42,644
Market Energy Sales Revenue ($)	$ 1,318,702	$ 998,988	$ 830,954	$ 2,661,834	$ 2,904,851	$ 3,476,647	$ 3,403,575	$ 3,997,494	$ 3,967,697	$ 3,810,366
Average Market Energy Sales Revenue ($/MWh)	$ 53.76	$ 51.15	$ 48.91	$ 68.99	$ 74.13	$ 75.73	$ 77.92	$ 84.81	$ 87.15	$ 89.35
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 39.72	$ 41.02	$ 42.28	$ 45.36	$ 48.58	$ 51.75	$ 55.00	$ 58.18	$ 60.29	$ 62.50
LMP Off-Peak Average ($/MWh)	$ 24.37	$ 24.82	$ 25.30	$ 26.99	$ 28.53	$ 30.12	$ 31.61	$ 33.18	$ 34.33	$ 35.29
Market Capacity										
Market Capacity Purchase (MW)	9	15	40	-	-	2	19	22	25	31
Market Capacity Cost ($/kW-mo)	$ 4.00	$ 4.08	$ 4.16	$ 4.24	$ 4.33	$ 4.42	$ 4.50	$ 4.59	$ 4.69	$ 4.78
Total Market Capacity Cost ($)	$ 439,429	$ 724,403	$ 1,974,680	$ -	$ -	$ 125,265	$ 1,009,638	$ 1,207,732	$ 1,413,017	$ 1,749,641
Unit Operating Capacity (MW)										
CC1	27	27	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	216	216	216	216	216
CROD On	216	216	216	216	216	216	216	216	216	216
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	1	1	1	1	1	4	4	4	4	4
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
Number of Starts										
CC1	3	2	-	-	-	-	-	-	-	-
CC2	37	23	15	16	18	17	16	19	17	16
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	107	107	116	109	116	122	111
Unit Generation (MWh)										
CC1	432	270	-	-	-	-	-	-	-	-
CC2	11,277	6,462	4,192	4,541	5,015	4,840	4,017	5,439	4,915	4,516
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	21,246	21,356	23,387	21,960	23,991	22,893	20,423
CROD OFF	760,826	773,361	786,601	798,348	812,728	823,817	836,952	850,659	868,233	876,518
CROD On	542,200	550,225	558,639	566,042	575,009	581,837	589,826	598,046	607,213	613,160
LZ	11,523	11,504	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504
OWEF (PPA)	479	479	479	479	479	479	479	479	479	479
SOLAR (PPA)	817	814	814	814	818	5,696	5,718	5,722	5,725	5,722
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
RPU Generation Subtotal (MWh)	23,233	18,236	15,696	37,292	37,888	39,732	37,481	40,835	39,326	36,443
CROD Subtotal (MWh)	1,303,026	1,323,586	1,345,240	1,364,390	1,387,738	1,405,654	1,426,778	1,448,705	1,473,447	1,489,677
PPA Purchase Subtotal (MWh)	1,296	1,293	1,283	1,293	1,298	6,174	6,197	6,201	6,204	6,201
Total Unit Generation (MWh)	1,327,555	1,343,115	1,362,229	1,402,974	1,426,922	1,451,560	1,470,456	1,495,840	1,518,976	1,532,321
Capacity Factor										
CC1	0.2%	0.1%								
CC2	2.6%	1.5%	1.0%	1.0%	1.1%	1.1%	0.9%	1.2%	1.1%	1.0%
CCGT										
CHP										
RENG				4.4%	4.4%	4.9%	4.6%	5.0%	4.8%	4.2%
Fuel Cost ($)										
CC1	$ 36,985	$ 25,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 709,869	$ 453,167	$ 320,464	$ 370,121	$ 435,928	$ 444,773	$ 390,827	$ 556,795	$ 527,296	$ 511,760
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ 1,366,031	$ 1,467,260	$ 1,692,672	$ 1,666,841	$ 1,925,774	$ 1,938,761	$ 1,820,208
Total Fuel Costs ($)	$ 746,853	$ 478,930	$ 320,464	$ 1,736,152	$ 1,903,188	$ 2,137,445	$ 2,057,668	$ 2,482,569	$ 2,466,057	$ 2,331,968
Variable O&M ($)										
CC1	$ 714	$ 448	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 18,540	$ 10,727	$ 7,126	$ 7,901	$ 8,977	$ 8,858	$ 7,552	$ 10,497	$ 9,683	$ 9,122
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ 166,595	$ 171,632	$ 192,656	$ 185,420	$ 207,636	$ 203,086	$ 185,700
CROD OFF	$ 31,398,662	$ 32,554,308	$ 33,773,894	$ 34,963,812	$ 36,305,470	$ 37,536,838	$ 38,898,029	$ 40,325,764	$ 41,895,356	$ 43,230,296
CROD On	$ 29,836,295	$ 30,986,936	$ 32,089,981	$ 33,165,541	$ 34,364,802	$ 35,468,276	$ 36,674,429	$ 37,929,244	$ 39,280,854	$ 40,458,821
Total Variable O&M Costs ($)	$ 61,354,212	$ 63,552,419	$ 65,871,001	$ 68,303,839	$ 70,850,881	$ 73,206,628	$ 75,765,430	$ 78,473,141	$ 81,378,979	$ 83,883,938
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1	$ 87.27	$ 97.08								
CC2	$ 64.59	$ 71.79	$ 78.15	$ 83.25	$ 88.72	$ 93.72	$ 99.17	$ 104.30	$ 109.25	$ 115.34
CCGT										
CHP										
RENG			$	$ 72.14	$ 76.74	$ 80.61	$ 84.35	$ 88.92	$ 93.58	$ 98.22
CROD OFF	$ 41.27	$ 42.09	$ 42.94	$ 43.80	$ 44.67	$ 45.56	$ 46.48	$ 47.41	$ 48.35	$ 49.32
CROD On	$ 55.21	$ 56.32	$ 57.44	$ 58.59	$ 59.76	$ 60.96	$ 62.18	$ 63.42	$ 64.68	$ 65.98
Fixed O&M ($)										
CC1	$ 314,190	$ 317,520	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 226,610	$ 229,041	$ 234,530	$ 240,518	$ 246,506	$ 252,993	$ 258,981	$ 265,468	$ 272,454	$ 278,941
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ 561,142	$ 677,671	$ 694,612	$ 711,978	$ 729,777	$ 748,021	$ 766,722
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 31,325,795	$ 31,520,589	$ 31,792,666	$ 32,034,918	$ 32,399,314	$ 32,563,196	$ 32,837,514	$ 33,092,167	$ 33,446,404	$ 33,536,299
LZ	$ 52,338	$ 53,219	$ 54,286	$ 55,373	$ 56,658	$ 57,632	$ 58,762	$ 59,944	$ 61,320	$ 62,387
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 5,946	$ 6,060	$ 6,238	$ 6,366	$ 6,906	$ 46,778	$ 47,987	$ 49,206	$ 50,604	$ 51,896
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Fixed O&M Costs ($)	$ 31,924,888	$ 32,126,430	$ 32,087,701	$ 32,998,317	$ 33,387,145	$ 33,615,212	$ 33,915,221	$ 34,196,562	$ 34,578,803	$ 34,696,044
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ -	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383
SOLAR (PPA)	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 343,604	$ 343,604	$ 343,604	$ 343,604	$ 343,604
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Payment	$ 79,363	$ 79,363	$ 79,363	$ 4,789,745	$ 4,789,745	$ 5,053,986	$ 5,053,986	$ 5,053,986	$ 5,053,986	$ 5,053,986
Total Variable ($, VOM + Fuel)	$ 62,101,065	$ 64,031,349	$ 66,191,465	$ 70,039,991	$ 72,754,069	$ 75,344,073	$ 77,823,099	$ 80,955,710	$ 83,845,037	$ 86,215,906
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 32,443,679	$ 32,930,196	$ 34,141,744	$ 37,788,063	$ 38,176,890	$ 38,794,463	$ 39,978,845	$ 40,458,281	$ 41,045,966	$ 41,489,672
Net Market Purchases (Sales) ($, Purchases less Sales)	$ (259,203)	$ 261,769	$ 561,091	$ (912,268)	$ (875,140)	$ (942,912)	$ (276,950)	$ (507,024)	$ (84,198)	$ 605,361
Total Power Supply Cost ($)	$ 94,285,541	$ 97,223,314	$ 100,894,300	$ 106,915,785	$ 110,055,819	$ 113,195,624	$ 117,524,994	$ 120,906,967	$ 124,806,825	$ 128,320,939
Total Power Supply Cost ($/MWh)	$ 71.38	$ 72.21	$ 73.52	$ 76.80	$ 77.32	$ 78.29	$ 79.83	$ 80.60	$ 81.50	$ 82.60

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Requirements (MWh)	1,582,000	1,609,697	1,640,901	1,664,201	1,691,300	1,717,197	1,748,004	1,772,801	1,804,300	1,836,400
Market Energy										
Market Energy Purchases (MWh)	70,795	78,594	85,667	97,949	111,114	1,717,197	1,744,025	1,772,801	1,804,300	1,836,400
Market Energy Purchases Cost ($)	$ 5,133,172	$ 5,814,662	$ 6,471,221	$ 7,563,607	$ 8,759,055	$ 110,242,103	$ 115,122,250	$ 120,082,732	$ 125,464,063	$ 131,180,376
Average Market Energy Purchase Cost ($/MWh)	$ 72.51	$ 73.98	$ 75.54	$ 77.22	$ 78.83	$ 64.20	$ 66.01	$ 67.73	$ 69.54	$ 71.43
Market Energy Sales (MWh)	40,208	40,608	43,646	218,258	214,348	1,024,020	1,010,638	979,945	991,093	983,339
Market Energy Sales Revenue ($)	$ 3,893,044	$ 3,918,083	$ 4,120,250	$ 15,145,889	$ 15,447,455	$ 80,377,778	$ 84,004,926	$ 82,101,413	$ 86,442,887	$ 87,112,430
Average Market Energy Sales Revenue ($/MWh)	$ 96.85	$ 96.42	$ 94.40	$ 70.04	$ 72.07	$ 78.49	$ 83.12	$ 83.78	$ 87.22	$ 88.59
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 64.78	$ 67.01	$ 69.34	$ 71.65	$ 73.82	$ 75.85	$ 78.18	$ 80.49	$ 82.73	$ 84.90
LMP Off-Peak Average ($/MWh)	$ 36.28	$ 37.29	$ 38.14	$ 39.17	$ 40.37	$ 41.30	$ 42.30	$ 43.15	$ 44.14	$ 45.15
Market Capacity										
Market Capacity Purchase (MW)	36	40	44	22	30	-	-	-	-	-
Market Capacity Cost ($/kW-mo)	$ 4.88	$ 4.97	$ 5.07	$ 5.17	$ 5.28	$ 5.38	$ 5.49	$ 5.60	$ 5.71	$ 5.83
Total Market Capacity Cost ($)	$ 2,097,753	$ 2,395,555	$ 2,686,915	$ 1,373,243	$ 1,876,435	$ -	$ -	$ -	$ -	$ -
Unit Operating Capacity (MW)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	317	317	317	317	317
CHP	-	-	-	32	32	32	32	32	32	32
RENG	55	55	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	-	-	-	-	-
CROD On	216	216	216	216	216	-	-	-	-	-
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	4	4	7	7	7	18	18	21	21	24
WIND (PPA)	-	-	-	-	-	150	150	150	150	150
Number of Starts										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	13	13	9	10	11	12	11	10	11	11
CCGT	-	-	-	-	-	122	122	114	116	112
CHP	-	-	-	13	19	14	15	16	9	17
RENG	104	100	100	95	88	82	89	82	84	76
Unit Generation (MWh)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	3,343	3,643	2,720	2,894	2,944	3,169	3,019	2,869	3,069	2,919
CCGT	-	-	-	-	-	340,787	329,163	295,258	306,480	296,177
CHP	-	-	-	170,311	175,538	175,941	174,894	173,349	173,284	173,751
RENG	19,160	19,270	18,282	15,372	14,164	16,086	13,725	14,603	14,329	11,749
CROD OFF	890,213	902,920	917,001	925,346	935,701	-	-	-	-	-
CROD On	620,909	627,860	635,225	639,430	644,485	-	-	-	-	-
LZ	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504	11,504	11,504
OWEF (PPA)	479	479	479	479	479	18,379	18,441	18,382	18,382	16,382
SOLAR (PPA)	5,722	5,742	10,649	10,600	10,620	29,357	29,445	34,308	34,325	39,137
WIND (PPA)	-	-	-	-	-	429,705	431,269	430,573	430,573	430,573
RPU Generation Subtotal (MWh)	34,008	34,417	32,519	208,082	204,151	547,497	532,319	497,583	508,668	496,100
CROD Subtotal (MWh)	1,511,121	1,530,779	1,552,226	1,564,777	1,580,185	-	-	-	-	-
PPA Purchase Subtotal (MWh)	6,201	6,221	11,127	11,078	11,098	477,441	479,154	483,264	483,281	488,092
Total Unit Generation (MWh)	1,551,329	1,571,417	1,595,872	1,781,937	1,795,435	1,024,938	1,011,473	980,847	991,947	984,192
Capacity Factor										
CC1										
CC2	0.8%	0.8%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
CCGT						12.3%	11.9%	10.6%	11.0%	10.7%
CHP				62.5%	62.2%	62.4%	62.0%	61.5%	61.4%	61.6%
RENG	4.0%	4.0%	3.8%	3.2%	2.9%	3.3%	2.9%	3.0%	3.0%	2.4%
Fuel Cost ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 396,132	$ 449,528	$ 349,257	$ 389,410	$ 412,275	$ 450,897	$ 454,787	$ 446,258	$ 493,961	$ 485,666
CCGT	$ -	$ -	$ -	$ -	$ -	$ 30,814,364	$ 30,824,475	$ 28,528,309	$ 30,771,023	$ 30,816,946
CHP	$ -	$ -	$ -	$ 8,137,308	$ 9,459,817	$ 9,848,592	$ 10,150,009	$ 10,421,775	$ 10,790,053	$ 11,172,540
RENG	$ 1,794,636	$ 1,877,056	$ 1,865,685	$ 1,639,590	$ 1,576,738	$ 1,853,740	$ 1,643,517	$ 1,805,871	$ 1,833,200	$ 1,555,443
Total Fuel Costs ($)	$ 2,190,768	$ 2,326,584	$ 2,214,943	$ 11,166,309	$ 11,448,829	$ 42,976,592	$ 43,072,788	$ 41,202,213	$ 43,888,237	$ 44,030,595
Variable O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 6,921	$ 7,759	$ 5,829	$ 6,454	$ 6,742	$ 7,446	$ 7,245	$ 7,087	$ 7,764	$ 7,581
CCGT	$ -	$ -	$ -	$ -	$ -	$ 1,327,523	$ 1,314,259	$ 1,208,355	$ 1,285,608	$ 1,273,479
CHP	$ -	$ -	$ -	$ 2,729,701	$ 2,785,680	$ 2,861,869	$ 2,915,968	$ 2,952,453	$ 3,035,387	$ 3,119,654
RENG	$ 178,574	$ 184,087	$ 179,013	$ 154,284	$ 145,716	$ 169,621	$ 148,348	$ 161,786	$ 162,710	$ 136,748
CROD OFF	$ 44,783,891	$ 46,331,575	$ 47,995,210	$ 49,400,630	$ 50,952,483	$ -	$ -	$ -	$ -	$ -
CROD On	$ 41,788,480	$ 43,102,515	$ 44,480,296	$ 45,670,286	$ 46,951,918	$ -	$ -	$ -	$ -	$ -
Total Variable O&M Costs ($)	$ 86,758,866	$ 89,625,937	$ 92,660,448	$ 97,961,355	$ 100,842,537	$ 4,366,458	$ 4,385,818	$ 4,339,681	$ 4,491,503	$ 4,537,442
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1										
CC2	$ 120.56	$ 125.54	$ 130.60	$ 136.78	$ 142.32	$ 147.52	$ 153.05	$ 158.00	$ 163.49	$ 168.96
CCGT					$	$ 94.31	$ 97.64	$ 100.71	$ 104.60	$ 108.35
CHP				$ 67.31	$ 69.76	$ 72.24	$ 74.71	$ 77.21	$ 79.78	$ 82.28
RENG	$ 102.99	$ 106.96	$ 111.84	$ 116.70	$ 121.61	$ 125.79	$ 130.55	$ 134.74	$ 139.29	$ 144.03
CROD OFF	$ 50.31	$ 51.31	$ 52.34	$ 53.39	$ 54.45					
CROD On	$ 67.30	$ 68.55	$ 70.02	$ 71.42	$ 72.85					
Fixed O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 285,927	$ 293,412	$ 300,398	$ 307,883	$ 315,867	$ 323,851	$ 331,835	$ 339,819	$ 348,302	$ 357,284
CCGT	$ -	$ -	$ -	$ -	$ -	$ 6,028,236	$ 6,178,942	$ 6,333,416	$ 6,491,751	$ 6,654,044
CHP	$ -	$ -	$ -	$ 846,258	$ 867,415	$ 889,100	$ 911,320	$ 934,111	$ 957,464	$ 981,400
RENG	$ 785,890	$ 805,537	$ 825,676	$ 846,318	$ 867,476	$ 889,162	$ 911,392	$ 934,176	$ 957,531	$ 981,469
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 33,718,273	$ 33,881,554	$ 34,086,336	$ 34,060,265	$ 34,078,584	$ -	$ -	$ -	$ -	$ -
LZ	$ 63,622	$ 64,809	$ 66,351	$ 67,509	$ 68,849	$ 70,241	$ 71,856	$ 73,078	$ 74,549	$ 76,020
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 52,939	$ 54,011	$ 103,945	$ 105,907	$ 100,678	$ 308,203	$ 318,166	$ 378,035	$ 387,382	$ 453,820
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 3,858,985	$ 3,974,434	$ 4,052,583	$ 4,152,736	$ 4,256,038
Total Fixed O&M Costs ($)	$ 34,906,651	$ 35,100,322	$ 35,382,706	$ 36,234,139	$ 36,307,869	$ 12,365,779	$ 12,697,952	$ 13,045,217	$ 13,369,714	$ 13,780,075
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506
CHP	$ -	$ -	$ -	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864
RENG	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383	$ 4,710,383
SOLAR (PPA)	$ 343,604	$ 343,604	$ 636,870	$ 636,870	$ 636,870	$ 1,812,410	$ 1,812,410	$ 3,707,998	$ 3,707,998	$ 5,660,881
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919
Total Payment	$ 5,053,986	$ 5,053,986	$ 5,347,253	$ 11,895,117	$ 11,895,117	$ 68,053,081	$ 68,053,081	$ 69,948,670	$ 69,948,670	$ 71,901,552
Total Variable ($, VOM + Fuel)	$ 88,948,534	$ 91,952,521	$ 94,875,390	$ 109,127,664	$ 112,291,365	$ 47,343,151	$ 47,458,616	$ 45,541,894	$ 48,379,740	$ 48,568,036
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 42,058,390	$ 42,549,864	$ 43,416,874	$ 49,502,499	$ 50,079,420	$ 80,418,860	$ 80,751,033	$ 82,993,887	$ 83,318,384	$ 85,661,628
Net Market Purchases (Sales) ($, Purchases less Sales)	$ 1,440,128	$ 1,896,579	$ 2,350,971	$ (7,582,283)	$ (6,688,400)	$ 29,864,326	$ 31,117,324	$ 37,981,320	$ 39,021,197	$ 44,067,947
Total Power Supply Cost ($)	$ 132,446,153	$ 136,398,964	$ 140,643,235	$ 151,047,881	$ 155,682,386	$ 157,626,337	$ 159,326,973	$ 166,517,101	$ 170,719,321	$ 178,297,610
Total Power Supply Cost ($/MWh)	$ 83.72	$ 84.74	$ 85.71	$ 90.76	$ 92.05	$ 91.70	$ 91.15	$ 93.92	$ 94.62	$ 97.09

Net Present Cost ($) $ 1,506,011,381

Rochester Public Utilities
2015 Update of the RPU Infrastructure Study
Project No. 82902
Path 3: Retire CC1 2018, peaking resource added in 2018, CHP added in 2020

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Annual Energy Requirements (MWh)	1,321,298	1,346,452	1,372,397	1,395,798	1,423,297	1,448,696	1,472,201	1,500,160	1,531,394	1,553,500
Market Energy										
Market Energy Purchases (MWh)	22,583	25,563	26,931	31,408	33,981	41,200	51,301	52,454	55,631	62,015
Market Energy Purchases Cost ($)	$ 1,059,558	$ 1,260,757	$ 1,392,044	$ 1,749,565	$ 2,029,511	$ 2,533,735	$ 3,126,525	$ 3,490,476	$ 3,883,499	$ 4,415,727
Average Market Energy Purchase Cost ($/MWh)	$ 44.93	$ 49.13	$ 52.87	$ 55.70	$ 59.72	$ 61.50	$ 60.95	$ 66.54	$ 69.81	$ 70.86
Market Energy Sales (MWh)	24,528	19,529	36,917	37,025	40,557	44,424	45,105	45,324	45,475	42,863
Market Energy Sales Revenue ($)	$ 1,318,782	$ 968,968	$ 2,364,533	$ 2,616,373	$ 3,009,140	$ 3,326,706	$ 3,563,538	$ 3,811,413	$ 3,960,818	$ 3,858,756
Average Market Energy Sales Revenue ($/MWh)	$ 53.76	$ 51.15	$ 64.05	$ 68.00	$ 74.19	$ 74.89	$ 79.00	$ 84.09	$ 87.10	$ 90.02
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 39.72	$ 41.02	$ 42.26	$ 45.36	$ 48.58	$ 51.75	$ 55.00	$ 58.18	$ 60.29	$ 62.60
LMP Off-Peak Average ($/MWh)	$ 24.37	$ 24.82	$ 25.30	$ 26.00	$ 28.53	$ 30.12	$ 31.61	$ 33.18	$ 34.33	$ 35.29
Market Capacity										
Market Capacity Purchase (MW)	9	15	-	-	-	2	19	22	25	31
Market Capacity Cost ($/kW-mo)	$ 4.00	$ 4.08	$ 4.16	$ 4.24	$ 4.33	$ 4.42	$ 4.50	$ 4.59	$ 4.69	$ 4.78
Total Market Capacity Cost ($)	$ 439,429	$ 724,403	$ -	$ -	$ -	$ 125,265	$ 1,009,638	$ 1,207,732	$ 1,413,017	$ 1,749,641
Unit Operating Capacity (MW)										
CC1	27	27	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	216	216	216	216	216
CROD On	216	216	216	216	216	216	216	216	216	216
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	1	1	1	1	1	4	4	4	4	4
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
Number of Starts										
CC1	3	2	-	-	-	-	-	-	-	-
CC2	57	23	15	16	18	17	16	19	17	16
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	106	104	113	114	115	115	123	109
Unit Generation (MWh)										
CC1	432	270	-	-	-	-	-	-	-	-
CC2	11,277	6,462	4,182	4,541	5,015	4,840	4,017	5,439	4,915	4,516
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	19,929	20,588	22,729	21,905	23,387	22,180	22,839	20,642
CROD OFF	760,826	773,351	786,601	796,348	812,728	823,617	836,952	850,659	866,233	878,518
CROD On	549,200	550,223	558,539	568,042	576,009	581,837	589,876	598,046	607,213	613,160
LZ	11,523	11,504	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504
OWEF (PPA)	479	479	479	479	479	479	479	479	479	479
SOLAR (PPA)	817	814	814	814	818	5,696	5,718	5,722	5,725	5,722
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
RPU Generation Subtotal (MWh)	23,233	18,238	35,525	38,633	39,291	38,250	38,909	39,123	39,271	38,663
CROD Subtotal (MWh)	1,303,026	1,323,565	1,345,240	1,364,390	1,387,738	1,405,654	1,426,778	1,448,705	1,473,447	1,489,677
PPA Purchase Subtotal (MWh)	1,296	1,293	1,293	1,293	1,296	6,174	6,197	6,201	6,204	6,201
Total Unit Generation (MWh)	1,327,555	1,343,115	1,382,157	1,402,315	1,428,295	1,450,078	1,471,884	1,494,029	1,518,921	1,532,540
Capacity Factor										
CC1	0.2%	0.1%								
CC2	2.6%	1.5%	1.0%	1.0%	1.1%	1.1%	0.9%	1.2%	1.1%	1.0%
CCGT										
CHP										
RENG			4.1%	4.3%	4.7%	4.6%	4.9%	4.6%	4.7%	4.3%
Fuel Cost ($)										
CC1	$ 36,085	$ 25,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 709,865	$ 453,157	$ 330,454	$ 370,121	$ 435,908	$ 444,773	$ 380,827	$ 556,795	$ 527,286	$ 511,760
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 1,203,956	$ 1,327,704	$ 1,555,830	$ 1,584,949	$ 1,783,538	$ 1,781,644	$ 1,934,120	$ 1,841,331
Total Fuel Costs ($)	$ 745,950	$ 478,920	$ 1,534,410	$ 1,697,825	$ 1,991,738	$ 2,029,722	$ 2,174,365	$ 2,338,439	$ 2,461,417	$ 2,353,091
Variable O&M ($)										
CC1	$ 714	$ 448	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 18,540	$ 10,727	$ 7,126	$ 7,901	$ 8,977	$ 8,858	$ 7,552	$ 10,497	$ 9,653	$ 9,122
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 152,443	$ 161,420	$ 182,562	$ 180,445	$ 197,472	$ 191,956	$ 202,999	$ 187,696
CROD OFF	$ 31,298,662	$ 32,554,308	$ 33,773,694	$ 34,963,612	$ 36,305,470	$ 37,536,538	$ 38,898,029	$ 40,325,764	$ 41,885,356	$ 43,230,295
CROD On	$ 29,936,296	$ 30,886,935	$ 32,089,881	$ 33,165,541	$ 34,384,802	$ 35,468,276	$ 36,674,429	$ 37,929,244	$ 39,280,654	$ 40,458,621
Total Variable O&M Costs ($)	$ 61,254,212	$ 63,452,419	$ 66,023,444	$ 68,298,674	$ 70,881,911	$ 73,194,417	$ 75,777,483	$ 78,457,462	$ 81,378,462	$ 83,885,835
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1	$ 87.27	$ 97.08								
CC2	$ 64.53	$ 71.79	$ 78.15	$ 83.25	$ 88.72	$ 93.72	$ 99.17	$ 104.30	$ 109.25	$ 115.34
CCGT										
CHP										
RENG			$ 68.06	$ 72.33	$ 76.49	$ 80.50	$ 84.70	$ 88.88	$ 93.56	$ 98.29
CROD OFF	$ 41.37	$ 42.09	$ 42.94	$ 43.80	$ 44.67	$ 45.56	$ 46.48	$ 47.41	$ 48.35	$ 49.32
CROD On	$ 55.21	$ 56.32	$ 57.44	$ 58.59	$ 59.76	$ 60.96	$ 62.18	$ 63.42	$ 64.69	$ 65.98
Fixed O&M ($)										
CC1	$ 314,199	$ 317,520	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 226,610	$ 229,041	$ 234,550	$ 240,518	$ 246,506	$ 252,993	$ 258,981	$ 265,469	$ 272,454	$ 278,941
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 645,017	$ 661,142	$ 677,571	$ 694,512	$ 711,976	$ 729,777	$ 748,021	$ 766,722
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 31,325,795	$ 31,520,589	$ 31,792,686	$ 32,034,818	$ 32,299,314	$ 32,563,196	$ 32,837,514	$ 33,092,167	$ 33,446,494	$ 33,536,299
LZ	$ 52,339	$ 53,219	$ 54,096	$ 55,373	$ 56,558	$ 57,632	$ 58,762	$ 59,944	$ 61,320	$ 62,387
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 5,046	$ 6,060	$ 6,208	$ 6,356	$ 6,998	$ 46,778	$ 47,687	$ 49,205	$ 50,694	$ 51,806
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Fixed O&M Costs ($)	$ 31,924,089	$ 32,126,430	$ 32,732,719	$ 32,998,317	$ 33,287,145	$ 33,615,212	$ 33,915,221	$ 34,196,562	$ 34,578,983	$ 34,696,044
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495
SOLAR (PPA)	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 343,604	$ 343,604	$ 343,604	$ 343,604	$ 343,604
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Payment	$ 79,363	$ 79,363	$ 4,674,858	$ 4,674,858	$ 4,674,858	$ 4,939,099	$ 4,939,099	$ 4,939,099	$ 4,939,099	$ 4,939,099
Total Variable ($, VOM + Fuel)	$ 62,101,065	$ 64,631,349	$ 67,547,864	$ 69,996,499	$ 72,853,670	$ 75,224,139	$ 77,951,849	$ 80,795,901	$ 83,829,909	$ 86,239,026
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 32,443,679	$ 32,930,196	$ 37,407,576	$ 37,673,175	$ 38,082,003	$ 38,679,576	$ 39,863,958	$ 40,343,393	$ 40,931,099	$ 41,384,784
Net Market Purchases (Sales) ($, Purchases less Sales)	$ (259,224)	$ 291,789	$ (972,489)	$ (866,808)	$ (979,629)	$ (792,970)	$ (436,913)	$ (320,943)	$ (77,319)	$ 556,971
Total Power Supply Cost ($)	$ 94,285,541	$ 97,823,314	$ 103,982,850	$ 106,802,866	$ 109,936,044	$ 113,110,745	$ 117,378,893	$ 120,818,351	$ 124,683,689	$ 128,180,780
Total Power Supply Cost ($/MWh)	$ 71.36	$ 72.21	$ 75.77	$ 76.52	$ 77.24	$ 78.23	$ 79.73	$ 80.54	$ 81.42	$ 82.51

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Requirements (MWh)	1,582,000	1,609,697	1,640,901	1,664,201	1,691,300	1,717,197	1,748,004	1,772,801	1,804,300	1,836,400
Market Energy										
Market Energy Purchases (MWh)	70,785	78,584	85,667	97,949	111,114	1,717,197	1,744,025	1,772,801	1,804,300	1,836,400
Market Energy Purchases Cost ($)	$ 5,133,172	$ 5,814,662	$ 6,471,221	$ 7,563,607	$ 8,759,055	$ 110,242,103	$ 115,122,250	$ 120,082,732	$ 125,464,083	$ 131,180,376
Average Market Energy Purchase Cost ($/MWh)	$ 72.51	$ 73.98	$ 75.54	$ 77.22	$ 78.83	$ 64.20	$ 66.01	$ 67.73	$ 69.54	$ 71.43
Market Energy Sales (MWh)	42,240	40,583	41,340	215,545	217,971	1,022,154	1,012,118	980,055	989,391	984,437
Market Energy Sales Revenue ($)	$ 3,918,266	$ 3,904,611	$ 3,785,530	$ 15,055,118	$ 15,970,450	$ 80,065,211	$ 84,263,759	$ 82,106,215	$ 86,180,320	$ 87,297,042
Average Market Energy Sales Revenue ($/MWh)	$ 92.76	$ 96.21	$ 91.57	$ 69.85	$ 73.27	$ 78.33	$ 83.25	$ 83.78	$ 87.10	$ 88.68
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 64.78	$ 67.01	$ 69.34	$ 71.55	$ 73.62	$ 75.85	$ 78.16	$ 80.49	$ 82.73	$ 84.93
LMP Off-Peak Average ($/MWh)	$ 36.28	$ 37.29	$ 38.14	$ 39.17	$ 40.37	$ 41.30	$ 42.30	$ 43.15	$ 44.14	$ 45.15
Market Capacity										
Market Capacity Purchase (MW)	38	40	44	22	30	-	-	-	-	-
Market Capacity Cost ($/kW-mo)	$ 4.88	$ 4.97	$ 5.07	$ 5.17	$ 5.28	$ 5.38	$ 5.40	$ 5.60	$ 5.71	$ 5.83
Total Market Capacity Cost ($)	$ 2,097,753	$ 2,395,555	$ 2,686,915	$ 1,373,243	$ 1,876,435	$ -	$ -	$ -	$ -	$ -
Unit Operating Capacity (MW)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	317	317	317	317	317	317
CHP	-	-	-	32	32	32	32	32	32	32
RENG	55	55	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	-	-	-	-	-
CROD On	216	216	216	216	216	-	-	-	-	-
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	4	4	7	7	7	18	18	21	21	24
WIND (PPA)	-	-	-	-	-	150	150	150	150	150
Number of Starts										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	13	13	9	10	11	12	11	10	11	11
CCGT	-	-	-	-	-	122	122	114	118	112
CHP	-	-	-	13	19	14	15	16	9	17
RENG	111	101	87	94	95	92	87	86	78	82
Unit Generation (MWh)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	3,343	3,643	2,720	2,694	2,944	3,169	3,019	2,869	3,069	2,919
CCGT	-	-	-	-	-	340,797	329,163	295,258	306,480	296,177
CHP	-	-	-	176,311	175,538	175,941	174,894	173,349	173,284	173,751
RENG	21,191	19,215	15,976	14,658	17,788	14,219	15,207	14,713	12,627	12,847
CROD OFF	890,213	902,920	917,001	925,346	935,701	-	-	-	-	-
CROD On	620,908	627,860	635,225	639,430	644,485	-	-	-	-	-
LZ	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504	11,504	11,504
OWEF (PPA)	479	479	479	479	479	18,379	18,441	18,382	18,382	18,382
SOLAR (PPA)	5,722	5,742	10,649	10,600	10,620	29,357	29,445	34,308	34,325	39,137
WIND (PPA)	-	-	-	-	-	429,705	431,269	430,573	430,573	430,573
RPU Generation Subtotal (MWh)	36,039	34,362	30,213	205,368	207,774	545,630	533,801	497,693	506,964	497,198
CROD Subtotal (MWh)	1,511,121	1,530,779	1,552,226	1,564,777	1,580,185	-	-	-	-	-
PPA Purchase Subtotal (MWh)	6,201	6,221	11,127	11,078	11,098	477,441	479,154	483,264	483,281	488,092
Total Unit Generation (MWh)	1,553,361	1,571,362	1,593,566	1,781,223	1,799,058	1,023,071	1,012,956	980,957	990,245	985,290
Capacity Factor										
CC1										
CC2	0.8%	0.8%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
CCGT					0.0%	12.3%	11.9%	10.6%	11.0%	10.7%
CHP				62.5%	62.2%	62.4%	62.0%	61.5%	61.4%	61.6%
RENG	4.4%	4.0%	3.3%	3.0%	3.7%	3.0%	3.2%	3.1%	2.6%	2.7%
Fuel Cost ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 306,132	$ 449,528	$ 340,257	$ 380,410	$ 412,275	$ 450,897	$ 454,797	$ 446,258	$ 483,961	$ 485,666
CCGT	$ -	$ -	$ -	$ -	$ -	$ 30,814,364	$ 30,824,475	$ 28,528,309	$ 30,771,023	$ 30,816,046
CHP	$ -	$ -	$ -	$ 9,137,309	$ 9,459,817	$ 9,848,592	$ 10,150,009	$ 10,421,775	$ 10,790,053	$ 11,172,540
RENG	$ 1,977,821	$ 1,877,404	$ 1,634,911	$ 1,567,301	$ 1,968,479	$ 1,640,910	$ 1,816,544	$ 1,819,451	$ 1,618,167	$ 1,702,931
Total Fuel Costs ($)	$ 2,373,953	$ 2,326,933	$ 1,984,169	$ 11,094,020	$ 11,840,571	$ 42,763,863	$ 43,245,825	$ 41,215,793	$ 43,673,204	$ 44,170,083
Variable O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 6,921	$ 7,769	$ 5,929	$ 6,454	$ 6,742	$ 7,446	$ 7,245	$ 7,087	$ 7,764	$ 7,581
CCGT	$ -	$ -	$ -	$ -	$ -	$ 1,327,523	$ 1,314,259	$ 1,208,355	$ 1,285,638	$ 1,273,479
CHP	$ -	$ -	$ -	$ 2,729,701	$ 2,785,680	$ 2,861,869	$ 2,915,968	$ 2,962,453	$ 3,035,387	$ 3,119,654
RENG	$ 197,506	$ 183,562	$ 158,435	$ 147,121	$ 182,992	$ 149,938	$ 164,367	$ 163,002	$ 143,387	$ 149,528
CROD OFF	$ 44,783,891	$ 46,331,575	$ 47,995,210	$ 49,400,630	$ 50,952,483	$ -	$ -	$ -	$ -	$ -
CROD On	$ 41,769,480	$ 43,102,516	$ 44,480,296	$ 45,670,286	$ 46,951,916	$ -	$ -	$ -	$ -	$ -
Total Variable O&M Costs ($)	$ 86,777,798	$ 89,625,412	$ 92,637,870	$ 97,954,192	$ 100,879,813	$ 4,346,776	$ 4,401,840	$ 4,340,898	$ 4,472,177	$ 4,550,222
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1										
CC2	$ 120.56	$ 125.54	$ 130.60	$ 136.78	$ 142.32	$ 147.52	$ 153.05	$ 158.00	$ 163.49	$ 168.96
CCGT					$	$ 94.31	$ 97.64	$ 100.71	$ 104.60	$ 108.35
CHP			$	$ 67.31	$ 69.76	$ 72.24	$ 74.71	$ 77.21	$ 79.78	$ 82.26
RENG	$ 102.65	$ 107.26	$ 112.13	$ 116.06	$ 120.95	$ 125.95	$ 130.26	$ 134.74	$ 139.51	$ 144.20
CROD OFF	$ 50.31	$ 51.31	$ 52.34	$ 53.30	$ 54.45					
CROD On	$ 67.30	$ 68.65	$ 70.02	$ 71.42	$ 72.85					
Fixed O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 285,927	$ 293,412	$ 300,398	$ 307,883	$ 315,867	$ 323,851	$ 331,835	$ 339,819	$ 348,302	$ 357,284
CCGT	$ -	$ -	$ -	$ -	$ -	$ 6,028,236	$ 6,178,942	$ 6,333,415	$ 6,401,751	$ 6,654,044
CHP	$ -	$ -	$ -	$ 846,258	$ 867,415	$ 889,100	$ 911,328	$ 934,111	$ 957,464	$ 981,400
RENG	$ 785,890	$ 805,537	$ 825,676	$ 846,318	$ 867,476	$ 889,162	$ 911,392	$ 934,176	$ 957,531	$ 981,469
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 33,718,273	$ 33,881,554	$ 34,086,336	$ 34,060,265	$ 34,078,584	$ -	$ -	$ -	$ -	$ -
LZ	$ 63,622	$ 64,800	$ 66,351	$ 67,509	$ 68,849	$ 70,241	$ 71,856	$ 73,078	$ 74,540	$ 76,020
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 52,939	$ 54,811	$ 103,945	$ 105,907	$ 109,670	$ 308,203	$ 318,166	$ 378,035	$ 387,382	$ 453,820
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 3,858,985	$ 3,974,434	$ 4,052,583	$ 4,152,736	$ 4,256,038
Total Fixed O&M Costs ($)	$ 34,906,651	$ 35,100,322	$ 35,382,706	$ 36,234,139	$ 36,307,869	$ 12,385,779	$ 12,697,952	$ 13,045,217	$ 13,359,714	$ 13,760,075
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506
CHP	$ -	$ -	$ -	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864	$ 6,547,864
RENG	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495
SOLAR (PPA)	$ 343,604	$ 343,604	$ 636,870	$ 636,870	$ 636,870	$ 1,812,410	$ 1,812,410	$ 3,707,998	$ 3,707,998	$ 5,660,881
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919
Total Payment	$ 4,939,099	$ 4,939,099	$ 5,232,366	$ 11,780,230	$ 11,780,230	$ 67,938,194	$ 67,938,194	$ 69,833,782	$ 69,833,782	$ 71,786,665
Total Variable ($, VOM + Fuel)	$ 89,151,751	$ 91,952,346	$ 94,622,038	$ 109,048,212	$ 112,720,384	$ 47,110,638	$ 47,647,665	$ 45,556,691	$ 48,145,380	$ 48,728,305
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 41,943,503	$ 42,434,976	$ 43,301,986	$ 49,387,612	$ 49,964,533	$ 80,303,973	$ 80,636,146	$ 82,879,000	$ 83,203,497	$ 85,546,740
Net Market Purchases (Sales) ($, Purchases less Sales)	$ 1,214,916	$ 1,910,051	$ 2,685,691	$ (7,491,511)	$ (7,211,395)	$ 30,176,892	$ 30,858,491	$ 37,976,517	$ 39,283,763	$ 43,883,335
Total Power Supply Cost ($)	$ 132,310,171	$ 136,297,373	$ 140,609,716	$ 150,944,313	$ 155,473,523	$ 157,591,503	$ 159,142,302	$ 166,412,207	$ 170,632,640	$ 178,158,380
Total Power Supply Cost ($/MWh)	$ 83.63	$ 84.67	$ 85.69	$ 90.70	$ 91.93	$ 91.77	$ 91.04	$ 93.86	$ 94.57	$ 97.02

Net Present Cost ($) $ 1,507,624,365

Rochester Public Utilities
2015 Update of the RPU Infrastructure Study
Project No. 82902
Path 4: Retire CC1 2018, peaking resource added in 2018, CHP added in 2026

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Annual Energy Requirements (MWh)	1,321,298	1,346,402	1,372,397	1,395,798	1,423,297	1,445,898	1,472,201	1,500,100	1,531,394	1,553,500
Market Energy										
Market Energy Purchases (MWh)	23,583	25,553	26,331	31,408	33,981	41,200	51,301	52,454	55,631	62,315
Market Energy Purchases Cost ($)	$ 1,059,558	$ 1,250,757	$ 1,392,044	$ 1,749,565	$ 2,029,511	$ 2,533,735	$ 3,126,525	$ 3,480,470	$ 3,863,499	$ 4,415,727
Average Market Energy Purchase Cost ($/MWh)	$ 44.93	$ 49.13	$ 52.87	$ 55.70	$ 59.72	$ 61.50	$ 60.95	$ 66.54	$ 69.81	$ 70.86
Market Energy Sales (MWh)	24,528	19,529	36,917	38,584	39,185	45,906	43,678	47,135	45,530	42,644
Market Energy Sales Revenue ($)	$ 1,318,762	$ 998,968	$ 2,364,633	$ 2,661,834	$ 2,904,651	$ 3,476,647	$ 3,403,575	$ 3,997,484	$ 3,967,697	$ 3,810,355
Average Market Energy Sales Revenue ($/MWh)	$ 53.76	$ 51.15	$ 64.05	$ 68.99	$ 74.13	$ 75.73	$ 77.92	$ 84.81	$ 87.15	$ 89.35
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 39.72	$ 41.02	$ 42.28	$ 45.38	$ 48.58	$ 51.75	$ 55.00	$ 58.18	$ 60.29	$ 62.50
LMP Off-Peak Average ($/MWh)	$ 24.37	$ 24.82	$ 25.30	$ 26.99	$ 28.53	$ 30.12	$ 31.61	$ 33.18	$ 34.33	$ 35.29
Market Capacity										
Market Capacity Purchase (MW)	9	15	-	-	-	2	19	22	25	31
Market Capacity Cost ($/kW-mo)	$ 4.00	$ 4.08	$ 4.16	$ 4.24	$ 4.33	$ 4.42	$ 4.50	$ 4.59	$ 4.69	$ 4.78
Total Market Capacity Cost ($)	$ 439,429	$ 724,403	$ -	$ -	$ -	$ 125,265	$ 1,009,638	$ 1,207,732	$ 1,413,017	$ 1,749,641
Unit Operating Capacity (MW)										
CC1	27	27	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	216	216	216	216	216
CROD On	216	216	216	216	216	216	216	216	216	216
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	1	1	1	1	1	4	4	4	4	4
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
Number of Starts										
CC1	3	2	-	-	-	-	-	-	-	-
CC2	37	23	15	16	18	17	16	19	17	16
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	-	107	107	116	109	116	122	111
Unit Generation (MWh)										
CC1	432	270	-	-	-	-	-	-	-	-
CC2	11,277	6,462	4,192	4,541	5,015	4,840	4,017	5,439	4,915	4,518
CCGT	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-
RENG	-	-	19,929	21,246	21,356	23,387	21,960	23,991	22,893	20,420
CROD OFF	760,826	773,361	786,601	798,349	812,728	823,817	836,952	850,659	866,233	876,518
CROD On	542,200	550,225	558,639	566,042	575,009	581,837	589,826	598,046	607,213	613,150
LZ	11,523	11,504	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504
OWEF (PPA)	479	479	479	479	479	479	479	479	479	479
SOLAR (PPA)	817	814	814	814	818	5,896	5,716	5,722	5,725	5,722
WIND (PPA)	-	-	-	-	-	-	-	-	-	-
RPU Generation Subtotal (MWh)	23,233	18,236	35,625	37,292	37,888	39,732	37,481	40,935	39,326	36,443
CROD Subtotal (MWh)	1,303,026	1,323,586	1,345,240	1,364,390	1,387,738	1,405,654	1,426,778	1,448,705	1,473,447	1,489,677
PPA Purchase Subtotal (MWh)	1,296	1,293	1,293	1,293	1,296	6,174	6,197	6,201	6,204	6,201
Total Unit Generation (MWh)	1,327,555	1,343,115	1,382,157	1,402,974	1,426,922	1,451,560	1,470,456	1,495,840	1,518,976	1,532,321
Capacity Factor										
CC1	0.2%	0.1%								
CC2	2.6%	1.5%	1.0%	1.0%	1.1%	1.1%	0.9%	1.2%	1.1%	1.0%
CCGT										
CHP										
RENG			4.1%	4.4%	4.4%	4.9%	4.6%	5.0%	4.8%	4.2%
Fuel Cost ($)										
CC1	$ 36,985	$ 25,763	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 709,869	$ 453,167	$ 320,464	$ 370,121	$ 435,928	$ 444,773	$ 390,827	$ 556,795	$ 527,296	$ 511,760
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 1,203,956	$ 1,366,031	$ 1,467,260	$ 1,692,672	$ 1,666,841	$ 1,925,774	$ 1,938,761	$ 1,820,208
Total Fuel Costs ($)	$ 746,853	$ 478,930	$ 1,524,419	$ 1,736,152	$ 1,903,188	$ 2,137,445	$ 2,057,669	$ 2,482,569	$ 2,466,057	$ 2,331,968
Variable O&M ($)										
CC1	$ 714	$ 448	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 18,540	$ 10,727	$ 7,126	$ 7,901	$ 8,977	$ 8,858	$ 7,552	$ 10,497	$ 9,683	$ 9,122
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 152,443	$ 169,585	$ 171,632	$ 192,656	$ 185,420	$ 207,638	$ 203,080	$ 185,700
CROD OFF	$ 31,398,662	$ 32,554,308	$ 33,773,894	$ 34,963,812	$ 36,305,470	$ 37,536,838	$ 38,898,029	$ 40,325,764	$ 41,885,356	$ 43,230,295
CROD On	$ 29,936,295	$ 30,886,936	$ 32,089,981	$ 33,165,541	$ 34,364,802	$ 35,468,276	$ 36,674,429	$ 37,929,244	$ 39,280,854	$ 40,458,821
Total Variable O&M Costs ($)	$ 61,354,212	$ 63,552,419	$ 66,023,444	$ 68,303,839	$ 70,850,881	$ 73,206,828	$ 75,765,430	$ 78,473,141	$ 81,378,979	$ 83,883,938
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1	$ 87.27	$ 97.06								
CC2	$ 64.59	$ 71.79	$ 78.15	$ 83.25	$ 88.72	$ 93.72	$ 99.17	$ 104.30	$ 109.25	$ 115.34
CCGT										
CHP										
RENG			$ 68.06	$ 72.14	$ 76.74	$ 80.61	$ 84.35	$ 88.92	$ 93.56	$ 96.22
CROD OFF	$ 41.27	$ 42.09	$ 42.94	$ 43.80	$ 44.67	$ 45.56	$ 46.48	$ 47.41	$ 48.35	$ 49.32
CROD On	$ 55.21	$ 56.32	$ 57.44	$ 58.59	$ 59.76	$ 60.96	$ 62.18	$ 63.42	$ 64.69	$ 65.98
Fixed O&M ($)										
CC1	$ 314,199	$ 317,520	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 226,610	$ 229,041	$ 234,530	$ 240,518	$ 246,506	$ 252,993	$ 258,981	$ 265,468	$ 272,454	$ 279,941
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 645,017	$ 661,142	$ 677,671	$ 694,612	$ 711,978	$ 729,777	$ 748,021	$ 756,722
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 31,325,795	$ 31,520,589	$ 31,792,666	$ 32,034,910	$ 32,299,314	$ 32,563,196	$ 32,837,514	$ 33,092,167	$ 33,446,494	$ 33,536,269
LZ	$ 52,338	$ 53,219	$ 54,296	$ 55,373	$ 56,658	$ 57,632	$ 58,762	$ 59,944	$ 61,320	$ 62,387
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 5,046	$ 6,060	$ 6,208	$ 6,366	$ 6,996	$ 46,778	$ 47,987	$ 49,208	$ 50,694	$ 51,696
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Fixed O&M Costs ($)	$ 31,924,888	$ 32,128,430	$ 32,732,718	$ 32,998,317	$ 33,387,145	$ 33,615,212	$ 33,915,221	$ 34,196,562	$ 34,578,983	$ 34,686,044
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CHP	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
RENG	$ -	$ -	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495
SOLAR (PPA)	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 79,363	$ 343,604	$ 343,604	$ 343,604	$ 343,604	$ 343,604
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Payment	$ 79,363	$ 79,363	$ 4,674,858	$ 4,674,858	$ 4,674,858	$ 4,939,099	$ 4,939,099	$ 4,939,099	$ 4,939,099	$ 4,939,099
Total Variable ($, VOM + Fuel)	$ 62,101,065	$ 64,031,349	$ 67,547,864	$ 70,039,991	$ 72,754,069	$ 75,344,073	$ 77,823,099	$ 80,955,710	$ 83,845,037	$ 86,215,906
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 32,443,679	$ 32,930,196	$ 37,407,576	$ 37,673,175	$ 38,062,003	$ 38,679,576	$ 39,863,958	$ 40,343,393	$ 40,931,099	$ 41,384,784
Net Market Purchases (Sales) ($, Purchases less Sales)	$ (259,203)	$ 261,769	$ (972,589)	$ (912,268)	$ (875,140)	$ (942,912)	$ (276,950)	$ (507,024)	$ (84,188)	$ 605,351
Total Power Supply Cost ($)	$ 94,285,541	$ 97,223,314	$ 103,982,850	$ 106,800,898	$ 109,940,932	$ 113,080,737	$ 117,410,107	$ 120,792,080	$ 124,691,938	$ 128,206,081
Total Power Supply Cost ($/MWh)	$ 71.36	$ 72.21	$ 75.77	$ 76.52	$ 77.24	$ 78.21	$ 79.75	$ 80.52	$ 81.42	$ 82.53
Net Present Cost ($) $ 1,515,469,158										

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Annual Energy Requirements (MWh)	1,582,000	1,609,687	1,640,961	1,664,201	1,691,300	1,717,197	1,748,004	1,772,801	1,804,300	1,836,400
Market Energy										
Market Energy Purchases (MWh)	70,785	78,584	85,667	97,949	111,114	1,717,197	1,744,025	1,772,801	1,804,300	1,836,400
Market Energy Purchases Cost ($)	$ 5,133,172	$ 5,814,582	$ 6,471,221	$ 7,563,607	$ 8,759,055	$ 110,242,103	$ 115,122,250	$ 120,082,732	$ 125,464,083	$ 131,180,376
Average Market Energy Purchase Cost ($/MWh)	$ 72.51	$ 73.99	$ 75.54	$ 77.22	$ 78.83	$ 64.20	$ 66.01	$ 67.73	$ 69.54	$ 71.43
Market Energy Sales (MWh)	218,865	217,931	220,581	218,548	215,058	1,024,069	1,011,216	980,638	991,270	982,437
Market Energy Sales Revenue ($)	$ 13,999,241	$ 14,630,160	$ 15,178,205	$ 15,204,051	$ 15,484,642	$ 80,389,154	$ 84,081,654	$ 82,140,325	$ 86,479,560	$ 86,878,293
Average Market Energy Sales Revenue ($/MWh)	$ 64.28	$ 67.10	$ 68.78	$ 70.21	$ 72.00	$ 78.50	$ 83.15	$ 83.77	$ 87.24	$ 88.43
Market Pricing										
LMP On-Peak Average ($/MWh)	$ 64.78	$ 67.61	$ 69.34	$ 71.55	$ 73.82	$ 75.85	$ 78.16	$ 80.49	$ 82.73	$ 84.83
LMP Off-Peak Average ($/MWh)	$ 36.28	$ 37.20	$ 38.14	$ 39.17	$ 40.37	$ 41.30	$ 42.30	$ 43.15	$ 44.14	$ 45.15
Market Capacity										
Market Capacity Purchase (MW)	5	10	14	22	30	-	-	-	-	-
Market Capacity Cost ($/kW-mo)	$ 4.88	$ 4.97	$ 5.07	$ 5.17	$ 5.28	$ 5.38	$ 5.49	$ 5.60	$ 5.71	$ 5.83
Total Market Capacity Cost ($)	$ 307,580	$ 569,884	$ 824,732	$ 1,373,243	$ 1,876,435	$ -	$ -	$ -	$ -	$ -
Unit Operating Capacity (MW)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	50	50	50	50	50	50	50	50	50	50
CCGT	-	-	-	-	317	317	317	317	317	317
CHP	32	32	32	32	32	32	32	32	32	32
RENG	55	55	55	55	55	55	55	55	55	55
CROD OFF	216	216	216	216	216	-	-	-	-	-
CROD On	216	216	216	216	216	-	-	-	-	-
LZ	3	3	3	3	3	3	3	3	3	3
OWEF (PPA)	5	5	5	5	5	5	5	5	5	5
SOLAR (PPA)	4	4	7	7	7	18	18	21	21	24
WIND (PPA)	-	-	-	-	-	150	150	150	150	150
Number of Starts										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	13	13	9	10	11	12	11	10	11	11
CCGT	-	-	-	-	-	122	122	114	116	112
CHP	13	19	14	15	16	10	17	19	15	14
RENG	104	100	100	95	88	92	89	82	84	76
Unit Generation (MWh)										
CC1	-	-	-	-	-	-	-	-	-	-
CC2	3,343	3,643	2,720	2,894	2,944	3,169	3,019	2,869	3,069	2,919
CCGT	-	-	-	-	-	340,797	329,163	295,258	306,480	296,177
CHP	179,774	178,098	177,937	176,817	176,263	175,989	175,538	174,057	173,204	172,914
RENG	19,160	19,270	18,282	15,372	14,164	18,086	13,725	14,600	14,329	11,749
CROD OFF	890,213	903,920	917,001	925,346	935,701	-	-	-	-	-
CROD On	620,508	627,860	635,225	639,430	644,485	-	-	-	-	-
LZ	11,504	11,504	11,517	11,504	11,504	11,504	11,517	11,504	11,504	11,504
OWEF (PPA)	479	479	479	479	479	18,379	18,441	18,382	18,382	18,382
SOLAR (PPA)	5,722	5,742	10,648	10,600	10,620	29,357	29,445	34,308	34,325	39,137
WIND (PPA)	-	-	-	-	-	429,705	431,269	430,573	430,573	430,573
RPU Generation Subtotal (MWh)	212,782	212,515	210,455	206,388	204,875	547,545	532,963	488,292	508,588	495,263
CROD Subtotal (MWh)	1,511,121	1,530,779	1,552,228	1,564,777	1,580,185	-	-	-	-	-
PPA Purchase Subtotal (MWh)	6,201	6,221	11,127	11,078	11,098	477,441	479,154	483,264	483,281	488,092
Total Unit Generation (MWh)	1,730,104	1,749,515	1,773,809	1,782,243	1,796,159	1,024,986	1,012,117	981,555	991,866	983,355
Capacity Factor										
CC1										
CC2	0.8%	0.8%	0.6%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%
CCGT					0.0%	12.3%	11.9%	10.6%	11.0%	10.7%
CHP	63.4%	63.1%	63.1%	62.6%	62.5%	62.4%	62.2%	61.7%	61.4%	61.3%
RENG	4.0%	4.0%	3.8%	3.2%	2.0%	3.3%	2.9%	3.0%	3.0%	2.4%
Fuel Cost ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 366,132	$ 449,029	$ 349,257	$ 389,410	$ 412,275	$ 459,997	$ 454,797	$ 446,258	$ 403,061	$ 485,666
CCGT	$ -	$ -	$ -	$ -	$ -	$ 30,814,364	$ 30,824,475	$ 28,528,309	$ 30,771,023	$ 30,816,946
CHP	$ 8,143,675	$ 8,463,159	$ 8,646,042	$ 9,141,207	$ 9,498,316	$ 9,848,550	$ 10,186,951	$ 10,454,806	$ 10,793,291	$ 11,128,425
RENG	$ 1,794,636	$ 1,877,056	$ 1,855,685	$ 1,639,590	$ 1,576,736	$ 1,853,740	$ 1,643,517	$ 1,805,871	$ 1,833,200	$ 1,555,443
Total Fuel Costs ($)	$ 10,334,643	$ 10,809,743	$ 11,052,984	$ 11,170,207	$ 11,487,327	$ 42,976,651	$ 43,109,740	$ 41,235,245	$ 43,891,475	$ 43,984,480
Variable O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 6,921	$ 7,759	$ 5,929	$ 6,454	$ 6,742	$ 7,446	$ 7,245	$ 7,087	$ 7,764	$ 7,561
CCGT	$ -	$ -	$ -	$ -	$ -	$ 1,327,523	$ 1,314,259	$ 1,268,355	$ 1,285,638	$ 1,273,479
CHP	$ 2,570,213	$ 2,624,504	$ 2,687,585	$ 2,734,437	$ 2,797,177	$ 2,862,655	$ 2,926,705	$ 2,974,560	$ 3,033,977	$ 3,104,623
RENG	$ 178,574	$ 184,067	$ 173,013	$ 154,234	$ 145,716	$ 169,621	$ 146,346	$ 161,786	$ 162,713	$ 136,748
CROD OFF	$ 44,793,891	$ 46,331,575	$ 47,995,210	$ 49,400,630	$ 50,952,483	$ -	$ -	$ -	$ -	$ -
CROD On	$ 41,789,480	$ 43,102,515	$ 44,480,295	$ 45,670,286	$ 46,951,916	$ -	$ -	$ -	$ -	$ -
Total Variable O&M Costs ($)	$ 89,339,079	$ 92,250,421	$ 95,349,132	$ 97,966,091	$ 100,854,034	$ 4,367,244	$ 4,396,556	$ 4,351,788	$ 4,490,093	$ 4,522,410
Total Dispatch Cost (Fuel + Variable O&M) ($/MWh)										
CC1										
CC2	$ 120.58	$ 125.54	$ 130.60	$ 136.76	$ 142.32	$ 147.52	$ 153.05	$ 158.00	$ 163.49	$ 168.96
CCGT					$	$ 94.31	$ 97.64	$ 100.71	$ 104.60	$ 108.35
CHP	$ 59.83	$ 62.37	$ 64.83	$ 67.24	$ 69.76	$ 72.23	$ 74.71	$ 77.15	$ 79.83	$ 82.30
RENG	$ 102.09	$ 106.96	$ 111.84	$ 116.70	$ 121.81	$ 125.79	$ 130.55	$ 134.74	$ 139.29	$ 144.03
CROD OFF	$ 50.31	$ 51.31	$ 52.34	$ 53.39	54.45					
CROD On	$ 67.30	$ 68.65	$ 70.02	$ 71.42	72.85					
Fixed O&M ($)										
CC1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CC2	$ 285,927	$ 293,412	$ 300,388	$ 307,833	$ 315,867	$ 323,851	$ 331,835	$ 339,819	$ 348,302	$ 357,284
CCGT	$ -	$ -	$ -	$ -	$ -	$ 6,028,236	$ 6,178,942	$ 6,333,415	$ 6,491,751	$ 6,654,044
CHP	$ 765,655	$ 805,481	$ 825,518	$ 846,258	$ 867,415	$ 889,100	$ 911,328	$ 934,111	$ 957,464	$ 981,400
RENG	$ 785,890	$ 805,537	$ 825,676	$ 846,319	$ 867,476	$ 889,162	$ 911,392	$ 934,176	$ 957,531	$ 981,469
CROD OFF	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CROD On	$ 33,716,272	$ 33,881,654	$ 34,066,336	$ 34,060,565	$ 34,078,564	$ -	$ -	$ -	$ -	$ -
LZ	$ 63,622	$ 64,900	$ 66,351	$ 67,609	$ 68,849	$ 70,241	$ 71,856	$ 73,078	$ 74,549	$ 76,020
OWEF (PPA)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
SOLAR (PPA)	$ 52,338	$ 54,811	$ 103,945	$ 105,667	$ 109,678	$ 308,203	$ 318,168	$ 378,035	$ 387,382	$ 453,820
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 3,856,985	$ 3,974,434	$ 4,052,583	$ 4,152,736	$ 4,256,038
Total Fixed O&M Costs ($)	$ 35,692,406	$ 35,905,600	$ 36,208,324	$ 36,234,139	$ 36,307,869	$ 12,365,779	$ 12,697,952	$ 13,045,217	$ 13,369,714	$ 13,760,075
Debt Service & Demand Charge										
CCGT	$ -	$ -	$ -	$ -	$ -	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506	$ 32,862,506
CHP	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343	$ 6,080,343
RENG	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495	$ 4,595,495
SOLAR (PPA)	$ 343,604	$ 343,604	$ 636,870	$ 636,870	$ 636,870	$ 1,812,410	$ 1,812,410	$ 3,707,998	$ 3,707,998	$ 5,660,881
WIND (PPA)	$ -	$ -	$ -	$ -	$ -	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919	$ 22,119,919
Total Payment	$ 11,019,442	$ 11,019,442	$ 11,312,708	$ 11,312,708	$ 11,312,708	$ 67,470,673	$ 67,470,673	$ 69,366,261	$ 69,366,261	$ 71,319,143
Total Variable ($, VOM + Fuel)	$ 99,663,722	$ 103,060,164	$ 106,411,117	$ 109,136,299	$ 112,341,361	$ 47,343,895	$ 47,506,296	$ 45,587,032	$ 48,381,568	$ 48,506,890
Total Fixed ($, FOM + Mkt Cap + Debt Service & Demand Charge)	$ 47,018,807	$ 47,495,129	$ 48,345,764	$ 48,920,091	$ 49,497,012	$ 79,836,452	$ 80,168,625	$ 82,411,478	$ 82,735,975	$ 85,079,219
Net Market Purchases (Sales) ($, Purchases less Sales)	$ (8,866,069)	$ (8,815,468)	$ (8,706,984)	$ (7,640,445)	$ (6,725,587)	$ 29,852,949	$ 31,040,596	$ 37,939,408	$ 38,984,523	$ 44,302,083
Total Power Supply Cost ($)	$ 137,817,461	$ 141,739,815	$ 146,049,897	$ 150,415,944	$ 155,112,788	$ 157,033,295	$ 158,715,516	$ 165,937,918	$ 170,102,067	$ 177,888,192
Total Power Supply Cost ($/MWh)	$ 87.12	$ 88.05	$ 89.01	$ 90.38	$ 91.71	$ 91.45	$ 90.80	$ 93.60	$ 94.28	$ 96.87

BURNS & McDONNELL

CREATE AMAZING.

Burns & McDonnell World Headquarters
9400 Ward Parkway
Kansas City, MO 64114
O 816-333-9400
F 816-333-3690
www.burnsmcd.com

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: 5/6/2016

Requested From: Minnesota Energy Resources Corporation Response Due: 5/18/2016

Analysts Requesting Information: Michael Ryan/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.	
48	Subject: Project Development

Please provide any, and all, presentations made by MERC to regulatory and other interested parties regarding the Rochester Project since the beginning of the planning phase.

If this information has already been provided in written comments, testimony, or in response to an earlier DOC information request, please identify the specific cite(s) or DOC information request number(s).

MERC Response:

Enclosed are copies of the following presentations made by MERC:

1. October 22, 2014 presentation to staff from the Minnesota Public Utilities Commission, the Department of Commerce, and the Office of the Attorney General;
2. June 26, 2015 presentation to staff from the Minnesota Public Utilities Commission, the Department of Commerce, and the Office of the Attorney General;
3. September 16, 2015 presentation to landowners and interested stakeholders at a public open house meeting for the Route Permit proceeding; and
4. February 29, 2016 presentation to landowners and interested stakeholders at a public information and scoping meeting for the Route Permit proceeding;

Response by: Amber Lee

Title: Regulatory and Leg. Affairs Mgr.

Department: Regulatory Affairs

Telephone: (651) 332-8965

List sources of information:

5. May 18, 2016 presentation to representatives from the Destination Medical Center Corporation, the City of Rochester, and the Destination Medical Center Economic Development Agency.

Response by: Amber Lee

Title: Regulatory and Leg. Affairs Mgr.

Department: Regulatory Affairs

Telephone: (651) 332-8965

List sources of information:

MERC Rochester Discussion

Dave Kult – General Manager
Shawn Gillespie – Manager, Gas Supply
Marc Jimerson – External Affairs Leader
Amber Lee – Manager, Gas Regulatory Services

June 26, 2015

Agenda

- ✓ Meeting objective
- ✓ Rochester integrity concerns
- ✓ Rochester growth
- ✓ Rochester pipeline expansion
  - Address integrity concern
  - Growth opportunity
  - Request For Proposal (RFP)
  - RFP Discussion
    - ➢ Proposals
    - ➢ Projected costs
    - ➢ Whom the RFP was awarded
- ✓ Recovery of costs discussion
  - Recovery through PGAC / distribution margin
  - Impacts on residential customers
- ✓ Meeting objective

Meeting Objective

- ✓ Provide information on addressing DMC growth announcement
- ✓ Feedback on expectations of growth
- ✓ Provide information on Request for Proposal (RFP)
- ✓ Provide information on submitted RFPs
- ✓ Provide information on whom RFP was awarded
- ✓ Feedback on RFP process/award
- ✓ Feedback on cost recovery
- ✓ Feedback on regulatory filing process/approval

Rochester Integrity Concerns

- ✓ Winter 2013/14 peak day – January 6, 2014
- ✓ Rochester 1B Gate Station – 72 psig (Mayo)
  - Contracted NNG capacity – 23,292 Dth (MERC 18,462 Dth)
  - January 6, 2014 usage – 15,602 Dth (LV curtailment)
- ✓ Rochester 1D Gate Station – 400 psig (RPU)
  - Contracted NNG capacity – 41,107 Dth (MERC 36,707 Dth)
  - January 6, 2014 usage – 44,449 Dth (LV curtailment)
- ✓ Majority growth – Rochester 1D Gate Station
- ✓ No incremental NNG capacity without pipeline expansion
- ✓ January 2013 Mayo announcement - DMC
  - $6 billion investment over next 20 years

Rochester Pipeline Expansion

- ✓ Address integrity concerns
  - MERC needs incremental capacity to meet firm load
  - Avoid loss of pipeline pressure due to lack of upstream firm capacity
- ✓ Present opportunity for growth
  - Address Mayo growth (DMC announcement)
    - $6 billion investment over 20 years
    - Potentially doubling workforce
    - Expected growth in Rochester/surrounding MERC communities

Rochester Pipeline Expansion

- ✓ MERC upstream pipeline RFP process
  - MERC Issued RFP on January 5, 2015
  - RFP was emailed to:
    - Northern Border Pipeline
    - Northern Natural Gas
    - Great Lakes Gas Transmission
    - Viking Gas Transmission
    - Encore Energy
  - RFP was also placed on MERC's website
  - RFP deadline of January 16, 2015
- ✓ MERC received three proposals
  - NNG
  - NBPL
  - Twin Eagle (unsolicited proposal)

Rochester Pipeline Expansion

- ✓ *RFP Evaluation*
  - *A matrix was developed assigning a weighted point value to multiple variables to each proposal*
  - *The highest total score was awarded the RFP*
- ✓ RFP was awarded to NNG
  - Least amount of capital costs
  - Least amount of construction
  - Least amount of construction time to be in service
  - Allows the most hourly flow flexibility
  - Having two feeds into Rochester instead of one
  - NNG fixed the rate so not subject to rate change
- ✓ RFP Awarded Con
  - Does not provide the opportunity to introduce upstream pipeline competition

Rochester Pipeline Expansion

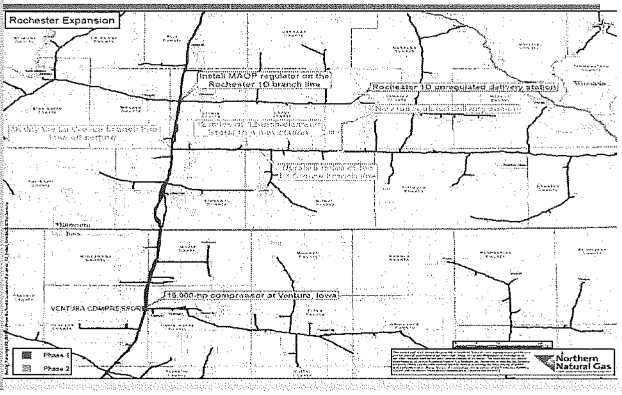
NNG Rochester Capacity Staging Plan

TBS 1D			Incremental	Total	Pressure
Phase	**Effective date**	**Pressure**	**Capacity (Dth/d)**	**Capacity (Dth/d)**	**(PSIG)**
Existing	5/27/2015	400 PSIG	3,200	39,907	350
Phase I (Add TFX Capacity)	8/1/2017	500 PSIG	10,500	47,207	450
Phase II (Add TFX Capacity)	11/1/2019-22	500 PSIG	0	47,207	500
Phase II (TFX Realignment)	11/1/2025	500 PSIG	0	47,207	500

TBS 1B			Incremental	Total	Pressure
Phase	**Effective date**	**Pressure**	**Capacity (Dth/d)**	**Capacity (Dth/d)**	**(PSIG)**
Existing	5/27/2015	72 PSIG	0	18,462	72
Phase I (Add TXF Capacity)	8/1/2017	500 PSIG	0	18,462	72
Phase II (Add TFX Capacity)	11/1/2019-22	500 PSIG	0	18,462	72
Phase II (TFX Realignment)	11/1/2025	500 PSIG	-3,338	15,124	72
Phase II (TF Realignment)	11/1/2025	500 PSIG	-15.124	0	-

New TBS			Incremental	Total	Pressure
Phase	**Effective date**	**Pressure**	**Capacity (Dth/d)**	**Capacity (Dth/d)**	**(PSIG)**
Existing	5/27/2015	NA	0	0	-
Phase II (Add TFX Capacity)	11/1/2019-22	500 PSIG	34,500	34,500	500
Phase II (TFX Realignment)	11/1/2025	500 PSIG	3,338	37,838	500
Phase II (TF Realignment)	11/1/2025	500 PSIG	15.124	52,962	500
	Total Capacity under firm NNG Agreements			**100,169**	

Rochester Pipeline Expansion (Work to be done by NNG)



Rochester Pipeline Expansion

Winter Period Year		Projected Rochester Design Day Forecast	Projected NNG Other Design Day Forecast	Projected Total NNG Design Day Forecast	Capacity 1D	Capacity 1B	Capacity New TBS	Rochester Total Capacity	Projected Rochester Reserve Margin	Projected NNG Other Capacity	Projected MERC NNG Total Capacity	Projected MERC NNG Reserve Margin	Projected Accum. Residential Impact
14	15	61,723	199,779	261,002	36,707	18,462	0	55,169	-9.9%	211,216	266,385	2.1%	
15	16	62,447	200,978	263,425	39,907	18,462	0	58,369	-6.5%	211,027	269,396	2.3%	
16	17	63,696	202,184	265,880	39,907	18,462	0	58,369	-8.4%	212,293	270,662	1.8%	
17	18	64,970	203,397	268,367	47,207	18,462	0	65,669	1.1%	213,566	279,235	4.0%	$ 14.30
18	19	66,270	204,617	270,887	47,207	18,462	0	65,669	-0.9%	214,848	280,517	3.6%	$ 13.69
19	20	67,595	205,845	273,440	47,207	18,462	34,500	100,169	48.2%	216,137	316,306	15.7%	$ 32.35
20	21	68,947	207,080	276,027	47,207	18,462	34,500	100,169	45.3%	217,434	317,603	15.1%	$ 31.57
21	22	70,326	208,322	278,648	47,207	18,462	34,500	100,169	42.4%	218,738	318,907	14.4%	$ 30.80
22	23	71,733	209,572	281,305	47,207	18,462	34,500	100,169	39.6%	220,051	320,220	13.8%	$ 30.03
23	24	73,167	210,830	283,997	47,207	18,462	34,500	100,169	36.9%	221,371	321,540	13.2%	$ 29.27
24	25	74,630	212,095	286,725	47,207	18,462	34,500	100,169	34.2%	222,699	322,868	12.6%	$ 28.52
25	26	76,123	213,367	289,490	47,207	0	52,962	100,169	31.6%	224,036	324,205	12.0%	$ 27.77
26	27	77,646	214,647	292,293	47,207	0	52,962	100,169	29.0%	225,380	325,549	11.4%	$ 27.02
27	28	79,198	215,935	295,134	47,207	0	52,962	100,169	26.5%	226,732	326,901	10.8%	$ 26.29
28	29	80,782	217,231	298,013	47,207	0	52,962	100,169	24.0%	228,092	328,261	10.1%	$ 25.56
29	30	82,398	218,534	300,932	47,207	0	52,962	100,169	21.6%	229,461	329,630	9.5%	$ 24.83
30	31	84,046	219,845	303,892	47,207	0	52,962	100,169	19.2%	230,838	331,007	8.9%	$ 24.11
31	32	85,727	221,165	306,892	47,207	0	52,962	100,169	16.8%	232,223	332,392	8.3%	$ 23.40
32	33	87,442	222,492	309,933	47,207	0	52,962	100,169	14.6%	233,616	333,785	7.7%	$ 22.69
33	34	89,190	223,826	313,017	47,207	0	52,962	100,169	12.3%	235,018	335,187	7.1%	$ 21.98
34	35	90,974	225,169	316,144	47,207	0	52,962	100,169	10.1%	236,428	336,597	6.5%	$ 21.29
35	36	92,794	226,520	319,314	47,207	0	52,962	100,169	7.9%	237,846	338,015	5.9%	$ 20.59
36	37	94,650	227,880	322,529	47,207	0	52,962	100,169	5.8%	239,274	339,443	5.2%	$ 19.91
37	38	96,543	229,247	325,789	47,207	0	52,962	100,169	3.8%	240,709	340,878	4.6%	$ 19.22
38	39	98,473	230,622	329,096	47,207	0	52,967	100,169	1.7%	242,153	342,322	4.0%	$ 18.55
39	40	100,443	232,006	332,449	47,207	0	52,962	100,169	-0.3%	243,606	343,775	3.4%	$ 17.88

MINNESOTA ENERGY RESOURCES

Rochester Looping

- ✓ MERC Looping Project Overview
  - Phase 1
    - ➢ Upgrade Northwest System – 400 psig to 275 psig
      - Install new District Regulator Station (DRS) off of 400 psig line to reduce pressure on high pressure loop
      - Rebuild 5 District Regulator Stations (DRSs) and add pressure monitoring
      - Reduce the number of DRSs by 3
      - Upgrade Parts Of Distribution System To Allow Standard Delivery Pressure
      - Reinforce distribution system to allow for reduced distribution feeds
      - Position NW area for more growth
      - Projected Cost - $5.6 Million (included in 2015 capital budget)
      - Projected Completion – November 1, 2015

MINNESOTA ENERGY RESOURCES

Rochester Looping

- ✓ MERC Looping Project Overview
  - Phase 2
    - ➢ Rebuild Rochester 1D TBS
    - ➢ Build new TBS for future growth
      - Install 5 miles of 12" steel pipe at 400 psig operating pressure between new TBS and Rochester 1D
      - Projected In-Service – November 1, 2019
    - ➢ Continue Loop Line
      - Install 10 miles of 12" steel pipe at 275 psig maximum operating pressure from new TBS to existing Rochester 1B TBS
      - Projected completion of 10 miles – November 1, 2025

MINNESOTA ENERGY RESOURCES

Regulatory Review Discussion

- ✓ Rochester Looping Project requires route permit (to be pursued by MERC)
  - Minn. Stat. Ch. 216G.02 and Minn. R. Ch. 7852
  - Discussion of routing plan and alternatives considered
  - Discussion of community outreach
  - Human and environmental impacts
- Timing of route permit review:
  - Route permit filing: November 2015
  - Processing (contested case assumed): through fall 2016
  - MPUC consideration: December 2016
- Rochester Looping Project calls for regulatory certainty
  - Project is important addition to MERC system and represents a material expansion
  - Regulatory concurrence of approach and cost is essential

MINNESOTA ENERGY RESOURCES

13

Regulatory Review Continued

- ✓ Rochester Looping Project does not require Certificate of Need
  - Project does not meet the definition of "large gas pipeline" in that it does not trigger the 50-mile requirement
  - Concurrence on need is important to project timelines and success
- ✓ Certificate of Need-Like Filing Proposed
  - Potentially use new Minn. Stat. 216B.1638 (2015 legislation) for review and potential rider recovery of portion of Project
  - Size, type and timing considerations will be detailed and how area in question is "underserved"
  - Certificate of need content requirements will be addressed in filing whether or not rider legislation is used
  - Concurrence in approach to project and proposed regulatory cost recovery.
- Timing of review (critical path):
  - Filing: September 2015
  - Processing (contested case assumed): through summer 2016
  - MPUC consideration: September 2016
- Requested outcome: approval of the prudence and desirability of the Rochester Looping Project and associated work.

MINNESOTA ENERGY RESOURCES

14

Regulatory Review Discussion

- ✓ Proposed NNG upstream upgrades cost recovery mechanism
  - MERC will seek approval to recover costs through the NNG PGAC
  - Projected project cost: $57.4 million
  - Projected Rochester total annual capacity cost (30 years)
    - Years 11/2017 through 10/2019 - $8.4 million
    - Years 11/2019 through 10/2042 - $13.3 million
    - Years 11/2042 through 10/2047 - $7.3 million
  - Projected annual residential customer rate impacts $14 - $32 (years 1 – 25)
  - Projected in-service date – August 1, 2017
- ✓ Proposed MERC looping cost recovery mechanism
  - MERC will seek approval to recover through distribution margin as part of rate base
  - Projected cost: $35.0 million (phase 2)
  - Projected annual residential customer rate impacts $11 - $32

MINNESOTA ENERGY RESOURCES

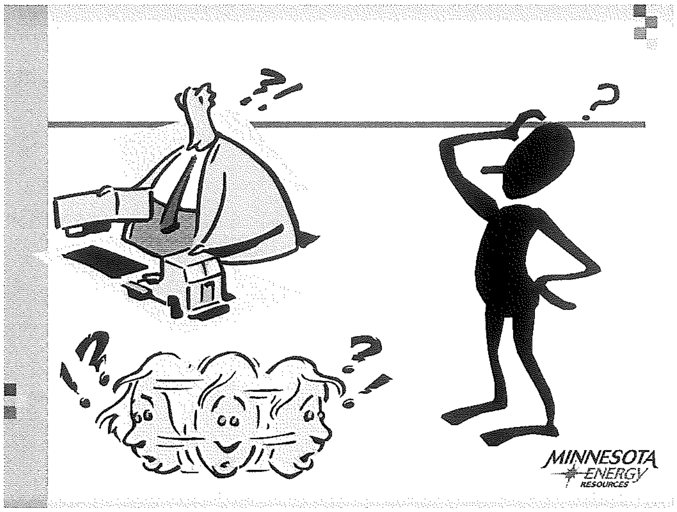
15

Meeting Objective

- ✓ Provide information on addressing DMC growth announcement
- ✓ Feedback on expectations of growth
- ✓ Provide information on Request for Proposal (RFP)
- ✓ Provide information on submitted RFPs
- ✓ Provide information on whom RFP was awarded
- ✓ Feedback on RFP process/award
- ✓ Feedback on cost recovery
- ✓ Feedback on regulatory filing process/approval

MINNESOTA ENERGY RESOURCES

16


MINNESOTA
ENERGY
RESOURCES

ROCHESTER AREA NATURAL GAS EXPANSION PROJECT

Community Information Meeting

Rory Lenton
External Affairs

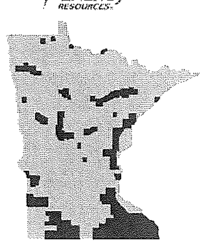
September 16, 2016

WELCOME

- *Thank you for coming!*
- Housekeeping

REGULATED OPERATIONS

- Business
  - Natural gas distribution operations for more than 80 years (acquired by Integrys Energy Group in 2006 and acquired by WEC Energy Group in 2015).
  - Regulated natural gas utility.
  - Operates in Minnesota (see map above).
  - 217 employees.
- Market
  - Provides natural gas distribution services to approximately 216,000 natural gas customers in 165 communities.
  - Natural gas revenues are comprised of 100% retail sales.
- Facilities
  - Natural gas property includes approximately 4,500 miles of distribution main, 50 miles of transmission main, 162 distribution and transmission gate stations, and 206,000 lateral services.

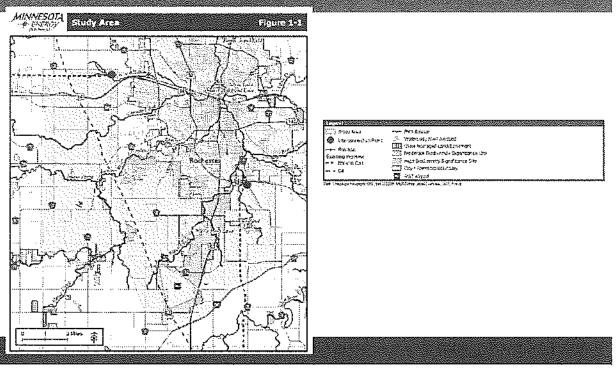


WHY THIS MEETING?

- Information exchange
- Mayo Clinic expansion, Destination Medical Center

MINNESOTA ENERGY RESOURCES

Current Rochester Natural Gas System



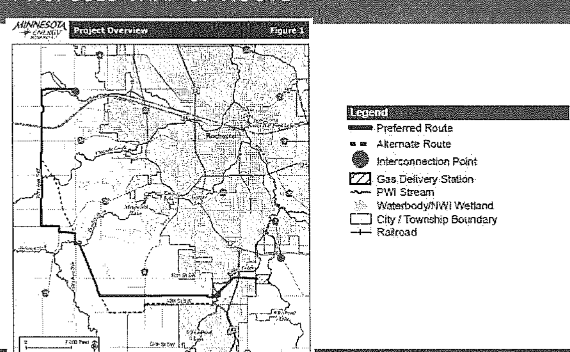
MINNESOTA ENERGY RESOURCES

Pipeline Routing Considerations

- Existing right of ways
- Along roadways
- Along property lines
- Environmental impact
- Social impact

MINNESOTA ENERGY RESOURCES

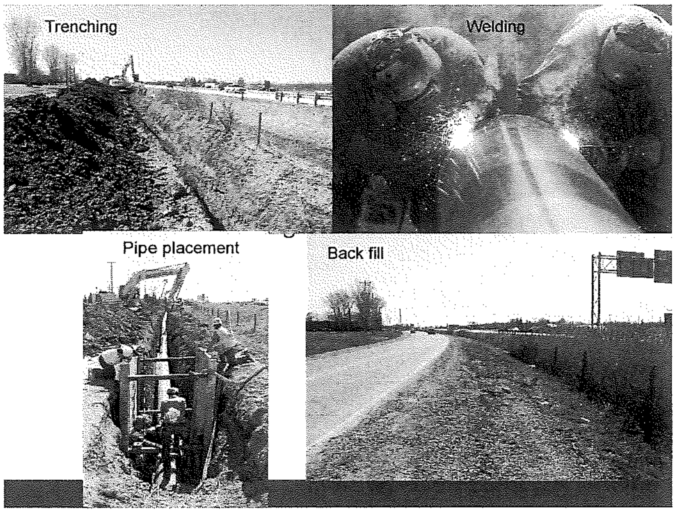
Proposed Map of Route



MINNESOTA ENERGY RESOURCES

Construction

- State-of-the-art trenching technology and directional underground drilling



Regulatory Process

- State Utility Commission
- State DNR
- State Dept of Ag
- State DOT
- State Water and Soil
- State Historical Society

Proposed Project Timeline

- Fall 2015 – Submit project to Regulators
  - (8 – 12 months) decision made
- Fall 2016 – Construction begins
  - 2017 project tested/operational

Community Meeting Stations

- Routing/maps
- Construction
- Real estate/easements
- Regulatory
- Mayo Expansion Project
- MERC General info
- Welcome
  - Info, one page Project Description, Minnesota Energy Resources program

More Information

- Project Updates

www.MinnesotaEnergyResources.com

Any Questions???

MINNESOTA ENERGY RESOURCES

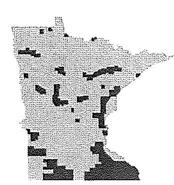
Rochester Natural Gas Pipeline Project

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

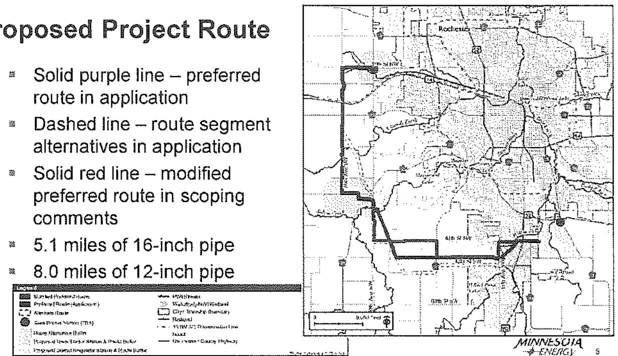
- Upgrade existing Rochester distribution system
  - Phase I completed in 2015 for $5.6 million
- Expand system to meet existing needs and growth
  - Phase II estimated at $44 million – construction 2017-22
- Add wholesale capacity – Northern Natural Gas
  - Significant capacity increase – long-term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

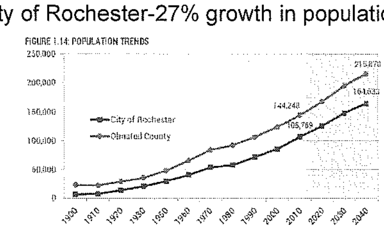


Need for the Project

- 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



Population Growth Increases Demand

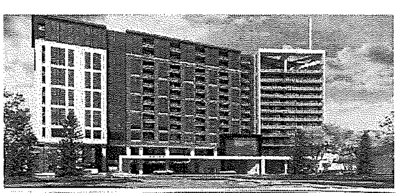
- Customer count projected to grow from 44,062 in 2015 to 53,469 in 2025 (20 percent increase)
- Corresponding 20 percent demand increase means 103.6 million therms in 2015 to 123.7 million in 2025

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

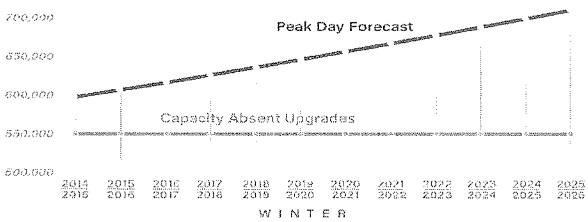
- Recently proposed $100 million housing and commercial development on Second Street SW
- 13 story building; underground parking; 359 housing units, and 20,000 square feet of commercial space



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

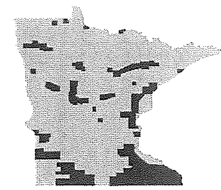
MINNESOTA ENERGY RESOURCES®

Rochester Natural Gas Pipeline Project
Docket No. G011/GP-15-858

Amber Lee
Regulatory and Legislative Affairs Manager
February 29, 2016

About Minnesota Energy Resources (MERC)

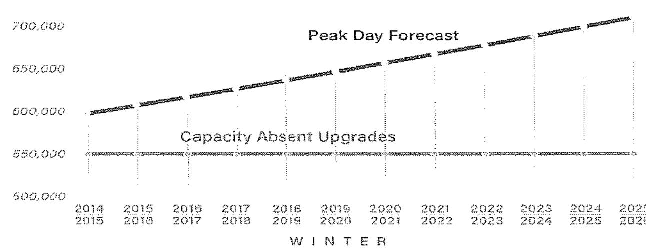
- Business
  - Natural gas distribution operations for 87 years
  - Regulated natural gas utility
  - 226 employees
- Market
  - Natural gas distribution services to approximately 230,000 natural gas customers in 177 communities
  - Minnesota customers only



Need for the Project

- Minnesota Energy Resources is sole natural gas provider in and around the city of Rochester
- Existing system has limited growth capabilities
- Project needed to provide reliable service:
  - To new commercial, industrial and residential customers
  - To meet the increased demand of existing customers

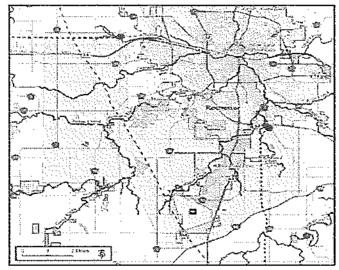
Need for the Project

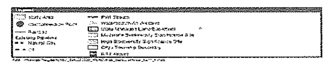


Project Overview

- West and south sides of Rochester
- Connect two town border stations (one existing and one new) and a district regulator station
  - Town border stations interface between our system and interstate natural gas pipelines
  - District regulator stations reduce pressure from our high-pressure natural gas pipelines (400-500 psig) to standard distribution pressure (60-100 psig)

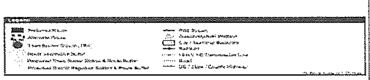
Route Development Study Area

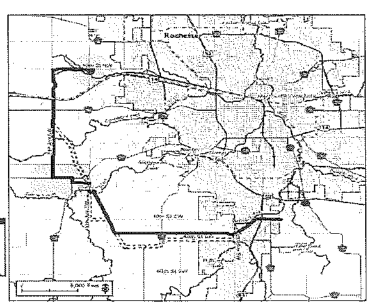




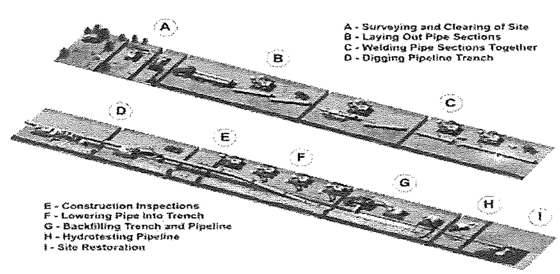
Proposed Map of Route

- Solid line – preferred route
- Dashed line – route segment alternatives
- 5.1 miles of 16-inch pipe
- 8.0 miles of 12-inch pipe

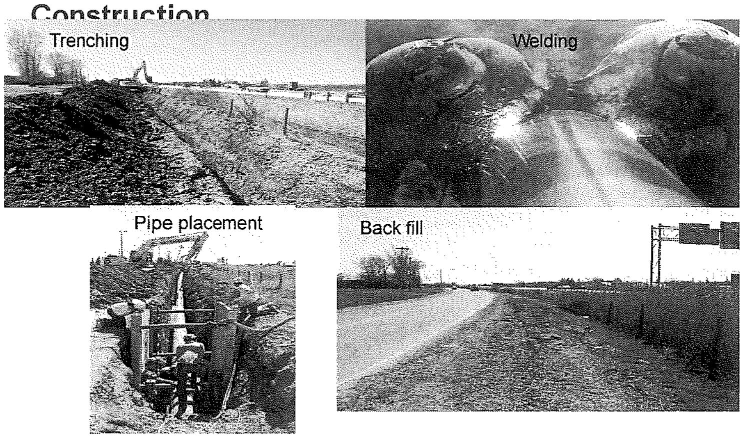




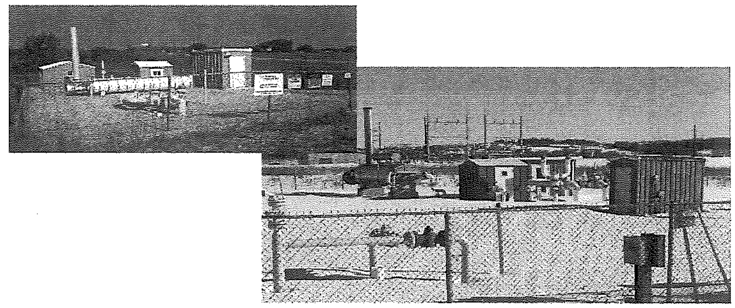
Construction



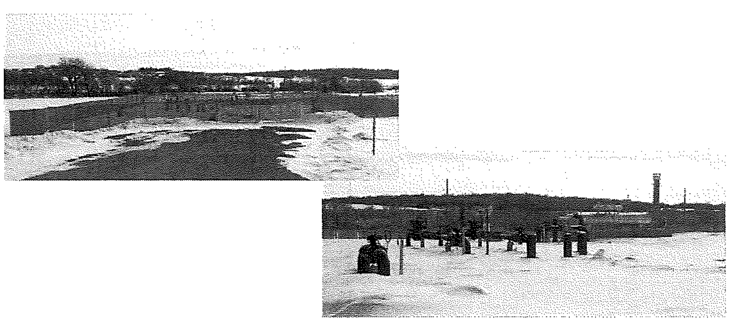
Construction



Town Border Station – Representative Photos



District Regulator Station – Representative Photos



MERC Rochester Discussion

Dave Kult – General Manager
Shawn Gillespie – Manager, Gas Supply
Marc Jimerson – External Affairs Leader
Amber Lee – Manager, Gas Regulatory Services

October 22, 2014

MINNESOTA ENERGY RESOURCES

1

Agenda

- ✓ Meeting Objective
- ✓ Rochester Integrity Concerns
- ✓ Rochester Growth
- ✓ Rochester Pipeline Expansion
  - Address Integrity Concern
  - Growth Opportunity
  - Potentially Promote Upstream Pipeline Competition
  - Project
    - ➢ Overview
    - ➢ Projected Costs
    - ➢ Alternatives Considered
- ✓ Recovery Of Costs Discussion
  - Recovery Through PGAC / Distribution Margin
  - Impacts On Residential Customers
- ✓ Meeting Objective

MINNESOTA ENERGY RESOURCES

2

Meeting Objective

- ✓ Provide Information On Addressing DMC Growth Announcement
- ✓ Feedback On Expectations of Growth
- ✓ Provide Information On Potential Operational Solutions
- ✓ Feedback On Proposals
- ✓ Feedback On Cost Recovery
- ✓ Feedback On Regulatory Approval

MINNESOTA ENERGY RESOURCES

3

Rochester Integrity Concerns

- ✓ Winter 2013/14 Peak Day – January 6, 2014
- ✓ Rochester 1B Gate Station – 72 psig (Mayo)
  - Contracted NNG Capacity – 23,292 Dth (MERC 18,462 Dth)
  - January 6, 2014 Usage – 15,602 Dth (LV Curtailment)
- ✓ Rochester 1D Gate Station – 400 psig (RPU)
  - Contracted NNG Capacity – 41,107 Dth (MERC 36,707 Dth)
  - January 6, 2014 Usage – 44,449 Dth (LV Curtailment)
- ✓ Majority Growth – Rochester 1D Gate Station
- ✓ No Incremental NNG Capacity Without Pipeline Expansion
- ✓ January 2013 Mayo Announcement - DMC
  - $6 Billion Investment Over Next 20 Years

MINNESOTA ENERGY RESOURCES

4

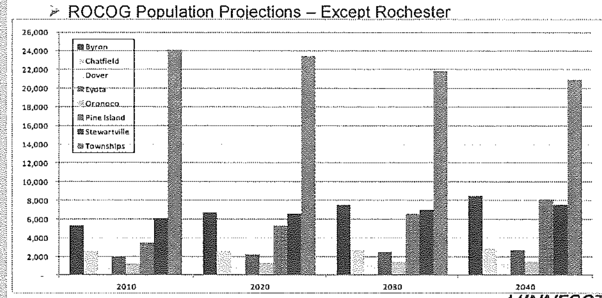
Projected Rochester Area Growth

- Rochester Area Growth:
  - ✓ ROCOG 2040 Long Range Plan
    - ➢ Population Forecasts
      - Olmstead County Seen 13.7% Growth 2000-2008 – Statewide Rate 6.9%
      - Rochester Seen 19.4% Growth 2000-2008,
      - Slight decrease In growth compared to the 1980' s At 22.1% And 1990' s At 21.7%
      - Rochester Is Approximately 72% Of Olmstead County Population
      - Projected To Be 77% of Olmstead County Population By 2040
      - Rochester Employs 94% Of Olmstead Population – Slight increase By 2040
      - Rochester Is 3rd Largest City In Minnesota
      - Economy Is Built Around Health Care, High Technology And Agriculture
      - Major Employers: Mayo, IBM Znd Seneca Foods
      - Mayo Znd IBM Employ Zpproximately 40,000
      - University of Minnesota –Rochester Established In 2007
      - Expect 5,000 Student Population By 2020 (414 in 2012)

MINNESOTA ENERGY RESOURCES

Projected Rochester Area Growth – Continued

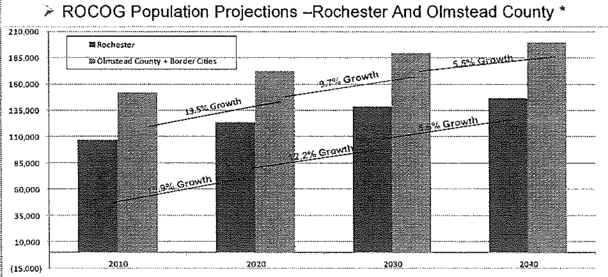
- Rochester Area Growth:
  - ➢ ROCOG Population Projections – Except Rochester



MINNESOTA ENERGY RESOURCES

Projected Rochester Area Growth – Continued

- Rochester Area Growth:
  - ➢ ROCOG Population Projections –Rochester And Olmstead County *

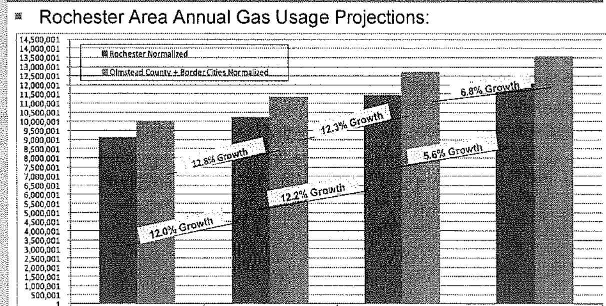


* Border Cities Chatfield (Fillmore Co.) And Pine Island (Goodhue Co.)

MINNESOTA ENERGY RESOURCES

Projected Rochester Area Growth – Continued

- Rochester Area Annual Gas Usage Projections:

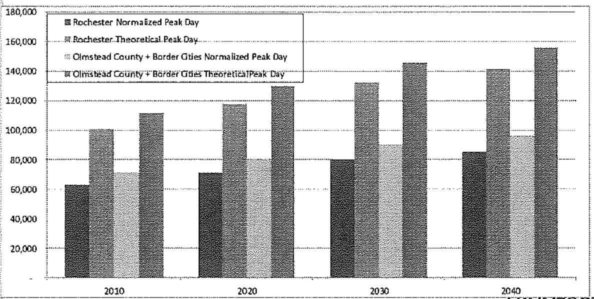


Border Cities Chatfield (Fillmore Co.) And Pine Island (Goodhue Co.)

MINNESOTA ENERGY RESOURCES

Projected Rochester Area Growth – Continued

- Rochester Area Normalized/Theoretical Peak Day Projections:



Border Cities Chatfield (Fillmore Co.) and Pine Island (Goodhue Co.)

Rochester Pipeline Expansion

- ✓ Address Integrity Concerns
  - MERC Needs Incremental Capacity To Meet Firm Load
  - Avoid Loss Of Pipeline Pressure Due To Lack of Upstream Firm Capacity
- ✓ Present Opportunity for Growth
  - Address Mayo Growth (DMC Announcement)
    - $6 Billion Investment Over 20 Years
    - Potentially Doubling Workforce
    - Expected Growth In Rochester/Surrounding MERC Communities
- ✓ MERC Reviewed/Discussed Several Alternatives
  - NNG Upgrades Existing System
  - Northern Border Pipeline (NBPL) Build From Ventura Iowa
  - MERC Build – (Ruled Out) Build From Ventura Iowa
  - MERC Loop Rochester System

Rochester Looping

- ✓ MERC Looping Project Overview –
  - Phase 1
    - Upgrade Existing System To Except 400 psig At Either 1B Or 1D
      - Reduce 4 District Regulator Stations (DSR)
      - DSR Reduction Accomplished By Looping Areas Of The City
      - Rebuild 2 DSRs
      - Upgrade Parts Of Distribution System To Allow Standard Delivery Pressure
      - Loop Approximately 3 ½ Miles Pipe In Northwestern Rochester
      - Install Pipe Crossing The Zumbro River On Far Northern Edge Rochester
      - Modifications/Additions Effectively/Safely Connect East/West Rochester To Accept 400 psig
      - Projected Cost - $5.6 Million
      - Projected In-Service – November 1, 2015

Rochester Looping

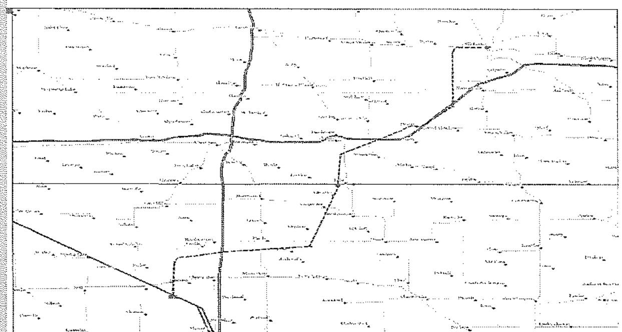
- ✓ MERC Looping Project Overview –
  - Phase 2
    - Tie Upgraded NNG And/Or NBPL Pipeline
      - Rebuild NNG TBS 1B To Accept 400 psig And Construct New DRS Or;
      - Build New TBS to Interconnect NBPL Pipeline
      - Install Approximately 75,000 ft Of New Pipe
      - If NNG Upgrade Is Chosen - Allows 400 psig Flow At TBS 1B Or 1D
      - If NBPL Pipeline Is Chosen – Allows 400 psig At New TBS And/Or At NNG 1D (backup)
      - Projected In-Service – October 1, 2017
  - Project Cost Paid By All MERC Customers In The Distribution Margin

Rochester Pipeline Expansion

✓ Proposed NNG Project Upgrade – Option 1
- NNG Construction Cost For Incremental 44,831 Dth/Day Capacity
  - Install 6,500 HP Compressor At La Crosse/Tomah Take-off
  - Rebuild La Crosse/Tomah Take-off
  - Pressure Test 8 Miles 16" Loop On La Crosse/Tomah Lateral
  - Install 5 Miles 12" Loop On La Crosse/Tomah Lateral
  - Install 8.8 Miles 12" Loop On Rochester 1B Branch Line
  - Expand Rochester 1B & 1D Town Border Stations
  - Projected Cost - $48 Million (+/- 30%)
  - Requested NNG Provide Level B Proposal (+/- 15%)
  - Projected In-Service Date – November 1, 2017
- MERC Currently Contracted With NNG – 55,169 Dth/Day Winter
- Total NNG Rochester Currently Contracted – 64,399 Dth/Day Winter
- Expansion Would Increase Capacity To 100,000 Dth/Day Capacity
- Project Cost Paid By NNG PGA Customers In Demand Entitlement Rate And Potentially MERC Transportation Customers

MINNESOTA ENERGY RESOURCES

NNG Proposed Upgrades



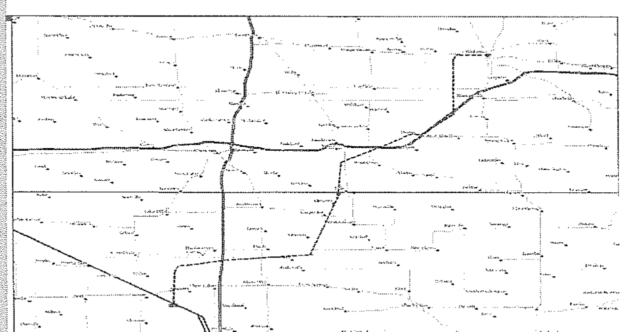
MINNESOTA ENERGY RESOURCES

Rochester Pipeline Expansion

✓ Proposed Project Overview – Option 2
- MERC Received New Pipeline Proposal From Northern Border Pipeline (NBPL)
  - 83.0 Miles 16" Steel
  - Interconnect NBPL Existing System Near Ventura, Iowa
  - Firm Capacity Of 100,000 Dth/day
  - Tie-In To New MERC Gate Station
  - 100,000 Dth/Day Firm MERC Capacity
  - Pipeline Capable Of Firm Deliverability Up To 130,000 Dth/day
  - Potential To Release Firm Capacity To Transport Customers (Mayo, RPU)
  - Projected Cost - $155 - $170.5 Million (+/- 10%)
  - Projected In-Service Date – November 1, 2017
- Need Expansion To Meet Projected Growth (See Page 8)
- Project Cost Paid By NNG PGA Customers In Demand Entitlement Rate And Potentially MERC Transportation Customers

MINNESOTA ENERGY RESOURCES

NBPL Proposed Pipeline Path



MINNESOTA ENERGY RESOURCES

Recovery of Costs Discussion

- ✓ NNG Proposal
  - MERC Will Seek Approval to Recover Costs Through The NNG PGAC
  - Projected Cost: $50.6 - $65.8 Million (+30%/-30%)
  - Projected Annual Cost Of Project Plus Current Capacity: $23.3 – $28.6 MM
  - Projected Annual Cost Per Residential Customer $65 - $85 (Years 1 – 20) $38 – After 20 Years
  - 20 Year Contract Term
  - Projected In-Service Date – November 1, 2017
- ✓ NBPL Proposal
  - MERC Will Seek Approval To Recover Costs Through The NNG PGAC
  - Projected Cost: $155.0 - $170.5 Million (+10%/-10%)
  - Projected Annual Cost Of Project: $19.2 – $20.2 Million (Years 1 – 25)
  - Projected Annual Cost Per Residential Customer $53 - $57 (Years 1 – 25) $2 – After 25 Years
  - 25 Year Contract Term
  - Projected In-Service Date – November 1, 2017

MINNESOTA ENERGY RESOURCES

Summary of Rochester Costs

Options	Projected Cost MM	Annual Projected Cost MM	Demand Rate Per Dth	Residential Annual Rate Impact
NNG 55,169 Current + 44,831 Dth	$50.6 – $65.8 *	$23.3 - $28.6 **	$0.7845 – $0.9684 **	$65 – $85 ****
NBPL 100,000 Dth	$155.0 – $170.5	$19.2 - $20.2 ***	$0.5260 – $0.5510 ***	$53 - $57 *****

*Does not include the cost of current capacity
**The projected annual cost is for a 20 year term. Does include the current cost of NNG capacity
***The projected annual cost is for a 25 year term
****Projected residential impact decreases to $38 after 20 years
*****Projected residential impact decreases to $2 after 25 years

MINNESOTA ENERGY RESOURCES

Summary of Worthington/Rochester Costs

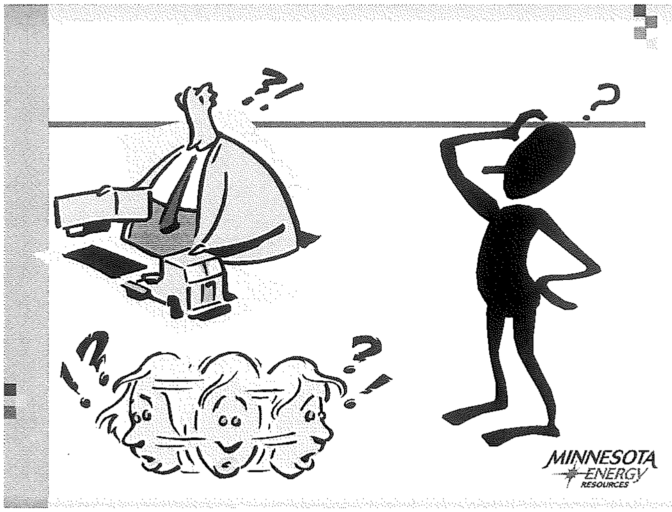
Options	Projected Cost MM	Annual Projected Cost MM	Demand Rate Per Dth	Residential Annual Rate Impact
EnerVantage + NNG Rochester Option		$25.9 - $31.4		$78 – $99
EnerVantage + NBPL Rochester Option		$21.8 - $23.0		$67 - $71

MINNESOTA ENERGY RESOURCES

Meeting Objective

- ✓ Provide Information on Addressing DMC Growth Announcement
- ✓ Feedback On Expectations of Growth
- ✓ Provide Information On Potential Operational Solutions
- ✓ Feedback On Proposals
- ✓ Feedback On Cost Recovery
- ✓ Feedback On Regulatory Approval

MINNESOTA ENERGY RESOURCES


MINNESOTA
ENERGY
RESOURCES

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

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St Paul, MN 55101-2147

IN THE MATTER OF THE APPLICATION OF MINNESOTA ENERGY RESOURCES CORPORATION FOR AUTHORITY OF RIDER RECOVERY FOR THE ROCHESTER NATURAL GAS EXTENSION FOR NATURAL GAS SERVICE IN MINNESOTA	MPUC Docket No. G011/M-15-895 OAH Docket No. 68-2500-3319

DIRECT ATTACHMENTS OF ADAM J. HEINEN (PART II – AJH-6 TO AJH-28, PAGE 13)

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

FINANCIAL ISSUES

JULY 1, 2016

MERC Peak Day Forecast (in Dekatherms)

97.50%

Demand Area	Weather Station Data (AHDD)								Weather Station Data (AHDD-1)								Analyses (2)							
	A								B								C	D	E	F = C + (A*D) + (B*E)	G	H	I = G*H	J = F + I
Pipeline	Bemidji	Fargo	International Falls	Ortonville	Cloquet	Minneapolis	Worthington	Rochester	Bemidji	Fargo	International Falls	Ortonville	Cloquet	Minneapolis	Worthington	Rochester	Base load	Use/ AHDD	Use/ AHDD-1	Point Estimate	Sigma	Factor Needed for Con fidence Level Above	Total Through put Peak Day Risk Adjustmnt	Total Throughput Peak Day w/ Risk Adjustment
2016	**2016**								**2016**								**2016**							
Centra			107								107						1,825	78	8	10,947	379	1.96	743	11,690
Subtotal GLGT	107				103				94				100				2,084	239	38	31,008	1,021	1.96	2,001	33,009
VGT		109								85							2,022	140	39	20,546	696	1.96	1,364	21,910
Consolidated Total																	5,931	457	84	62,501	2,096		4,108	66,609
NNG Cloquet					103								100				2,642	295	50	37,989	873	1.96	1,711	39,700
NNG Minneapolis						97								92			7,850	697	107	85,401	1,989	1.96	3,898	89,299
NNG Worthington							96								74		3,961	285	35	34,017	1,029	1.96	2,017	36,034
NNG Rochester								101								93.5	8,531	932	136	115,599	3,196	1.96	6,264	121,863
Subtotal NNG wo Ortonville					103	97	96	101					100	92	74	93.5	22,984	2,210	328	273,006	7,087	1.96	13,891	286,896
NNG Ortonville				95								86					(30)	10	1	1,002	27	1.96	53	1,055
NNG Total																	22,954	2,219	329	274,008	7,114		13,943	287,951
MERC Total																	28,886	2,677	413	336,509	9,210		18,051	354,560
2015	**2015**								**2015**								**2015**							
Centra			107								107						1,724	79	6	10,812	388	1.96	760	11,572
Subtotal GLGT	107				103				94				100				5,087	233	19	31,598	1,643	1.96	3,220	34,818
	78%				22%				78%				22%											
VGT		109								85							1,573	140	37	19,911	720	1.96	1,411	21,322
Consolidated Total																	8,383	453	61	62,321	2,751		5,391	67,712
Subtotal NNG wo Ortonville					103	97	96	101					100	92	74	93.5	31,542	2,350	258	289,116	6,877	1.96	13,479	302,596
					13%	28%	13%	45%					13%	28%	13%	45%								
NNG Ortonville				95								86					(52)	9	1	955	28	1.96	55	1,011
NNG Total																	31,490	2,359	260	290,072	6,906		13,535	303,606
MERC Total																	39,873	2,811	321	352,393	9,656		18,926	371,319
Difference	**Difference**								**Difference**								**Difference**							
Centra			0								0						101	(2)	2	135	(9)		(17)	118
Subtotal GLGT	0				0				0				0				(3,002)	6	19	(590)	(622)		(1,219)	(1,810)
VGT		0								0							449	0	2	634	(24)		(47)	588
Consolidated Total																	(2,452)	5	22	180	(655)		(1,283)	(1,103)
Subtotal NNG wo Ortonville					0	0	0	0					0	0	0	0	(8,558)	(140)	70	(16,111)	210		411	(15,699)
NNG Ortonville				0								0					22	0	(0)	47	(1)		(2)	45
NNG Total																	(8,536)	(139)	70	(16,064)	209		409	(15,655)
MERC Total																	(10,988)	(134)	92	(15,884)	(446)		(874)	(16,758)
	2/1/1996	1/18/1996	2/1/1996	1/14/2009	2/2/1996	2/2/1996	1/18/1996	2/2/1996	1/31/1996	1/17/1996	1/31/1996	1/13/2009	2/1/1996	2/1/1996	1/17/1996	2/1/1996								
	Coldest Adjusted HDD in 20 years (AHDD65)								Prior Day Adjusted HDD															

(2) Paper mills, taconites, direct-connects, and off-system end users with daily meters, and Lamb Weston were removed before regression.

MERC Peak Day Forecast (in Dekatherms)

Demand Area	Analyses (3)					97.50%			Adjustments			Final Result
	C	D	E	F = C + (A*D) + (B*E)	G	H	I = G*H	J = F + I	K	L = J*K	M	N = J + L + M
Pipeline	Base load	Use/ AHDD	Use/ AHDD-1	Point Estimate	Sigma	Factor Needed for Con fidence Level Above	Total Through put Peak Day Risk Adjustmnt	Total Throughput Peak Day w/ Risk Adjustment	Sales Forecast Growth Rate (4)	Sales Forecast Growth	(Add Back) Daily Firm Capacity	Total Peak Day Estimate
2016	**2016**								**2016**			**2016**
Centra	569	63	10	8,341	228	1.96	447	8,788	-1.3%	(114)		8,674
Subtotal GLGT	1,131	214	33	26,857	941	1.96	1,845	28,702		(373)	214	28,542
VGT	632	109	30	14,967	558	1.96	1,093	16,060	-1.3%	(209)	7	15,858
Consolidated Total	2,332	385	72	50,165	1,727		3,385	53,550		(696)	221	53,075
NNG Cloquet	1,928	264	40	33,082	716	1.96	1,403	34,484	-0.6%	(207)		34,278
NNG Minneapolis	2,224	632	94	72,293	1,767	1.96	3,463	75,756	-0.6%	(455)		75,302
NNG Worthington	1,145	254	31	27,850	796	1.96	1,560	29,410	-0.6%	(176)	95	29,329
NNG Rochester	6,214	842	103	101,060	2,546	1.96	4,990	106,050	-0.6%	(636)		105,414
Subtotal NNG wo Ortonville	11,511	1,992	268	234,285	5,825	1.96	11,416	245,701		(1,474)	95	244,322
NNG Ortonville	(30)	9	1	898	25	1.96	49	947	-0.6%	(6)		941
NNG Total	11,481	2,000	270	235,184	5,849		11,465	246,648		(1,480)	95	245,263
MERC Total	13,813	2,386	342	285,348	7,577		14,850	300,198		(2,176)	316	298,338
2015	**2015**								**2015**			**2015**
Centra								7,086	0.6%	43		7,128
Subtotal GLGT								25,353	0.6%	153	214	25,721
VGT								15,757	0.6%	95	7	15,858
Consolidated Total								48,195		290	221	48,707
Subtotal NNG wo Ortonville								258,245	0.006002	1,550	95	259,890
NNG Ortonville								1,011	0.6%	6		1,017
NNG Total								259,256		1,556	95	260,907
MERC Total								307,451		1,847	316	309,614
Difference	**Difference**								**Difference**			**Difference**
Centra								1,702		(157)		1,546
Subtotal GLGT								3,348		(527)	-	2,822
VGT								304		(303)	-	0
Consolidated Total								5,354		(987)	-	4,368
Subtotal NNG wo Ortonville								(12,544)		(3,024)	-	(15,568)
NNG Ortonville								(64)		(12)		(76)
NNG Total								(12,608)		(3,036)	-	(15,644)
MERC Total								(7,253)		(4,023)	-	(11,276)

(3) Paper mills, taconites, direct-connects, and off-system end users with daily meters, Lamb Weston, and, for 2016, interruptible meters were removed before regression.

(4) Source: Revenue Forecasting

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.	
16	Subject: Peak Demand Forecast Please provide any, and all, data, including raw data, used in the construction of Appendix E in the Company original *Petition*. These data should be provided in Microsoft Excel format with all links and formulae intact. 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 Excel file: Rochester Design Peak Day Analysis Sept 2015 Regressions corrected for AutoCor.xlsx. Each Town Border Station is on its own tab. Output files from the Regression models for each TBS are as follows: Blooming.xlsx Byron.xlsx Cannon.xlsx CannonFalls Corrected data.xlsx Clarement.xlsx

Response by: David Clabots List sources of information:

Title: Senior Project Specialist

Department: Treasury Dept.

Telephone: 920-433-1355

Dodge.xlsx
Dover.xlsx
Ellendale.xlsx
Eyota.xlsx
Hayfield.xlsx
Kasson.xlsx
Kenyon.xlsx
PineIsland.xlsx
Rochester.xlsx
Steele.xlsx
Stewartville.xlsx
Viola.xlsx
Wananmingo.xlsx
Westconcord.xlsx
Zumbrota.xlsx

Response by: David Clabots____________________ List sources of information:

Title: Senior Project Specialist______________ ________________________________

Department: Treasury Dept.____________________ ________________________________

Telephone: 920-433-1355____________________ ________________________________

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

Projected Design Day Assuming 1.6% Annual Growth										
	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
Winter Period	Byron	Claremont	Dodge Center	Kasson	Kenyon	Pine Island	Wanamingo	West Concord	Zumbrota	Steele
2015/16	2,439	305	2,157	3,479	1,086	1,583	703	547	1,653	144
2016/17	2,478	310	2,192	3,535	1,103	1,608	714	556	1,680	146
2017/18	2,518	315	2,227	3,592	1,121	1,634	725	565	1,706	149
2018/19	2,558	320	2,262	3,649	1,139	1,660	737	574	1,734	151
2019/20	2,599	325	2,299	3,707	1,157	1,687	749	583	1,761	154
2020/21	2,640	330	2,335	3,767	1,176	1,714	761	593	1,790	156
2021/22	2,683	336	2,373	3,827	1,194	1,741	773	602	1,818	159
2022/23	2,725	341	2,411	3,888	1,214	1,769	785	612	1,847	161
2023/24	2,769	347	2,449	3,950	1,233	1,798	798	622	1,877	164
2024/25	2,813	352	2,488	4,014	1,253	1,826	811	631	1,907	166
2025/26	2,858	358	2,528	4,078	1,273	1,856	824	642	1,937	169
2026/27	2,904	363	2,569	4,143	1,293	1,885	837	652	1,968	172
2027/28	2,951	369	2,610	4,209	1,314	1,915	850	662	2,000	174
2028/29	2,998	375	2,652	4,277	1,335	1,946	864	673	2,032	177
2029/30	3,046	381	2,694	4,345	1,356	1,977	878	684	2,064	180
2030/31	3,095	387	2,737	4,415	1,378	2,009	892	695	2,098	183
2031/32	3,144	393	2,781	4,485	1,400	2,041	906	706	2,131	186
2032/33	3,194	400	2,825	4,557	1,422	2,074	920	717	2,165	189
2033/34	3,245	406	2,871	4,630	1,445	2,107	935	728	2,200	192
2034/35	3,297	413	2,917	4,704	1,468	2,140	950	740	2,235	195
2035/36	3,350	419	2,963	4,779	1,492	2,175	965	752	2,271	198
2036/37	3,404	426	3,011	4,856	1,516	2,209	981	764	2,307	201
2037/38	3,458	433	3,059	4,934	1,540	2,245	996	776	2,344	204
2038/39	3,514	440	3,108	5,013	1,564	2,281	1,012	789	2,382	208
2039/40	3,570	447	3,157	5,093	1,589	2,317	1,029	801	2,420	211
2040/41	3,627	454	3,208	5,174	1,615	2,354	1,045	814	2,458	214
2041/42	3,685	461	3,259	5,257	1,641	2,392	1,062	827	2,498	218
2042/43	3,744	468	3,311	5,341	1,667	2,430	1,079	840	2,538	221
2043/44	3,804	476	3,364	5,427	1,694	2,469	1,096	854	2,578	225

NNG Capacity	937	316	1,352	2,026	1,079	928	533	511	1,669	0.00

Projected Firm Capacity Requirements Assuming 1.6% growth										
Winter Period	Byron	Claremont	Center	Kasson	Kenyon	Island	Wanamingo	Concord	Zumbrota	Steele
2017/18	2,518	315	2,227	3,592	1,121	1,634	725	565	1,706	149
2024/25	2,813	352	2,488	4,014	1,253	1,826	811	631	1,907	166
2033/34	3,245	406	2,871	4,630	1,445	2,107	935	728	2,200	192
2042/43	3,744	468	3,311	5,341	1,667	2,430	1,079	840	2,538	221

Projected Incremental Capacity Assuming 1.6% growth										
Winter Period	Byron	Claremont	Center	Kasson	Kenyon	Island	Wanamingo	Concord	Zumbrota	Steele
2017/18	1,581	(1)	875	1,566	42	706	192	54	37	149
2023/24	296	37	262	422	132	192	85	66	201	17
2032/33	432	54	382	616	192	280	124	97	293	26
2041/42	498	62	441	711	222	324	144	112	338	29

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

1.6% Cannon Falls	1.6% Dover	1.6% Eyota	1.6% Viola	1.6% Stewartville	1.6% Hayfield	1.6% Blooming Prairie	1.6% Ellandale	1.6% Rochester 1D 1B	1.6% Total	Current Firm Capacity	Projected Capacity Needed
3,137	335	873	103	3,534	896	1,571	485	59,969	85,001	74,129	10,872
3,187	340	887	105	3,590	910	1,597	493	60,929	86,361	74,129	12,232
3,238	346	902	107	3,648	925	1,622	500	61,904	87,743	74,129	13,614
3,290	351	916	108	3,706	940	1,648	508	62,894	89,147	74,129	15,018
3,343	357	931	110	3,765	955	1,675	517	63,901	90,573	74,129	16,444
3,396	362	946	112	3,826	970	1,701	525	64,923	92,022	74,129	17,893
3,451	368	961	114	3,887	985	1,729	533	65,962	93,495	74,129	19,366
3,506	374	976	115	3,949	1,001	1,756	542	67,017	94,990	74,129	20,861
3,562	380	992	117	4,012	1,017	1,784	550	68,089	96,510	74,129	22,381
3,619	386	1,008	119	4,076	1,034	1,813	559	69,179	98,055	74,129	23,926
3,677	392	1,024	121	4,142	1,050	1,842	568	70,286	99,623	74,129	25,494
3,736	399	1,040	123	4,208	1,067	1,871	577	71,410	101,217	74,129	27,088
3,795	405	1,057	125	4,275	1,084	1,901	586	72,553	102,837	74,129	28,708
3,856	412	1,074	127	4,344	1,101	1,932	596	73,714	104,482	74,129	30,353
3,918	418	1,091	129	4,413	1,119	1,963	605	74,893	106,154	74,129	32,025
3,980	425	1,108	131	4,484	1,137	1,994	615	76,091	107,852	74,129	33,723
4,044	432	1,126	133	4,555	1,155	2,026	625	77,309	109,578	74,129	35,449
4,109	439	1,144	135	4,628	1,173	2,058	635	78,546	111,331	74,129	37,202
4,175	446	1,162	137	4,702	1,192	2,091	645	79,802	113,113	74,129	38,984
4,241	453	1,181	140	4,778	1,211	2,125	655	81,079	114,922	74,129	40,793
4,309	460	1,200	142	4,854	1,231	2,159	666	82,377	116,761	74,129	42,632
4,378	467	1,219	144	4,932	1,250	2,193	677	83,695	118,629	74,129	44,500
4,448	475	1,238	146	5,011	1,270	2,228	687	85,034	120,527	74,129	46,398
4,519	482	1,258	149	5,091	1,291	2,264	698	86,394	122,456	74,129	48,327
4,592	490	1,278	151	5,172	1,311	2,300	710	87,777	124,415	74,129	50,286
4,665	498	1,299	154	5,255	1,332	2,337	721	89,181	126,406	74,129	52,277
4,740	506	1,320	156	5,339	1,354	2,374	732	90,608	128,428	74,129	54,299
4,816	514	1,341	158	5,425	1,375	2,412	744	92,058	130,483	74,129	56,354
4,893	522	1,362	161	5,511	1,397	2,451	756	93,531	132,571	74,129	58,442

2,479	275	880	56	3,371	878	1,250	420	55,169	74,129

Cannon Falls	Dover	Eyota	Viola	Stewartville	Hayfield	Blooming Prairie	Ellandale	Rochester 1D 1B	Total
3,238	346	902	107	3,648	925	1,622	500	61,904	87,743
3,619	386	1,008	119	4,076	1,034	1,813	559	69,179	98,055
4,175	446	1,162	137	4,702	1,192	2,091	645	79,802	113,113
4,816	514	1,341	158	5,425	1,375	2,412	744	92,058	130,483

Cannon Falls	Dover	Eyota	Viola	Stewartville	Hayfield	Blooming Prairie	Ellandale	Rochester 1D 1B	Total
759	71	22	51	277	47	372	80	6,735	13,614
381	41	106	13	429	109	191	59	7,275	10,312
556	59	155	18	626	159	278	86	10,624	15,058
641	68	178	21	722	183	321	99	12,255	17,371

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.	
18	Subject: Forecasting Please fully explain what, if any, relationship exists between the Rochester area sales forecasts (Attachment C) and the peak demand forecasts in Appendix E. 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 attached Excel file: Rochester Design Peak Day Analysis Sept 2015 Regressions corrected for AutoCor.xlsx; 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 the attached Excel

Response by: David Clabots______________________ List sources of information:

Title: Senior Project Specialist______________ ______________________________

Department: Treasury Dept.______________________ ______________________________

Telephone: 920-433-1355______________________ ______________________________ file: This was used Rochester Gas pipeline Certification_Rochester MN (9-1-2015).xlsx. 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 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.

Response by: David Clabots______________________ List sources of information:

Title: Senior Project Specialist_____________ ____

Department: Treasury Dept._____________________ ____

Telephone: 920-433-1355____________________ ____

Subp.3 A **Annual Gas Consumption by Ultimate Consumers and Customers**
Calendar Sales: Units MCF

Year	Residential	%chg	Residential Customers	%chg	Small Commercial	%chg	Small Commercial Customers	%chg	Large Commercial	%chg	Large Commercial Customers	%chg
2015	3,775,821		41,010		187,294		1,414		1,942,747		1,594	
2016	3,839,805	1.7%	41,554	1.3%	189,904	1.4%	1,437	1.6%	1,971,187	1.5%	1,623	1.8%
2017	3,897,836	1.5%	42,191	1.5%	192,395	1.3%	1,462	1.7%	1,984,300	0.7%	1,657	2.1%
2018	3,963,732	1.7%	42,912	1.7%	195,600	1.7%	1,493	2.1%	1,997,413	0.7%	1,685	1.7%
2019	4,036,917	1.8%	43,710	1.9%	199,162	1.8%	1,526	2.2%	2,010,526	0.7%	1,706	1.2%
2020	4,116,803	2.0%	44,579	2.0%	202,936	1.9%	1,561	2.3%	2,023,639	0.7%	1,723	1.0%
2021	4,202,899	2.1%	45,515	2.1%	206,858	1.9%	1,598	2.4%	2,036,752	0.6%	1,741	1.0%
2022	4,294,778	2.2%	46,513	2.2%	210,895	2.0%	1,635	2.3%	2,049,865	0.6%	1,761	1.1%
2023	4,392,056	2.3%	47,569	2.3%	215,031	2.0%	1,674	2.4%	2,062,978	0.6%	1,780	1.1%
2024	4,494,380	2.3%	48,679	2.3%	219,250	2.0%	1,714	2.4%	2,076,091	0.6%	1,800	1.1%
2025	4,601,424	2.4%	49,840	2.4%	223,544	2.0%	1,754	2.3%	2,089,203	0.6%	1,821	1.2%
10 Yr Average		2.0%		2.0%		1.8%		2.2%		0.7%		1.3%

Retail Usage and Customers

Year	Residential		Residential Customers		Small Commercial		Small Commercial Customers		Large Commercial		Large Commercial Customers	
2015	3,775,821		41,010		187,294		1,414		1,942,747		1,594	
2016	3,839,805	1.7%	41,554	1.3%	189,904	1.4%	1,437	1.6%	1,971,187	1.5%	1,623	1.8%
2017	3,897,836	1.5%	42,191	1.5%	192,395	1.3%	1,462	1.7%	1,984,300	0.7%	1,657	2.1%
2018	3,963,732	1.7%	42,912	1.7%	195,600	1.7%	1,493	2.1%	1,997,413	0.7%	1,685	1.7%
2019	4,036,917	1.8%	43,710	1.9%	199,162	1.8%	1,526	2.2%	2,010,526	0.7%	1,706	1.2%
2020	4,116,803	2.0%	44,579	2.0%	202,936	1.9%	1,561	2.3%	2,023,639	0.7%	1,723	1.0%
2021	4,202,899	2.1%	45,515	2.1%	206,858	1.9%	1,598	2.4%	2,036,752	0.6%	1,741	1.0%
2022	4,294,778	2.2%	46,513	2.2%	210,895	2.0%	1,635	2.3%	2,049,865	0.6%	1,761	1.1%
2023	4,392,056	2.3%	47,569	2.3%	215,031	2.0%	1,674	2.4%	2,062,978	0.6%	1,780	1.1%
2024	4,494,380	2.3%	48,679	2.3%	219,250	2.0%	1,714	2.4%	2,076,091	0.6%	1,800	1.1%
2025	4,601,424	2.4%	49,840	2.4%	223,544	2.0%	1,754	2.3%	2,089,203	0.6%	1,821	1.2%
		2.0%		2.0%		1.8%		2.2%		0.7%		1.3%

Interruptible	%chg	Interruptible Customers	%chg	Transport	%chg	Transport Customers	%chg	Total Sales	Total %chg	Total Customers	%chg	Year	
209,938		23		4,243,574		21		10,359,373		44,062		2015	2015
218,496	4.1%	23	0.0%	4,339,091	2.3%	22	4.8%	10,558,483	1.9%	44,659	1.4%	2016	2016
225,055	3.0%	23	0.0%	4,485,095	3.4%	23	4.5%	10,784,681	2.1%	45,356	1.6%	2017	2017
227,576	1.1%	23	0.0%	4,613,319	2.9%	24	4.3%	10,997,640	2.0%	46,137	1.7%	2018	2018
228,545	0.4%	23	0.0%	4,707,954	2.1%	25	4.2%	11,183,105	1.7%	46,990	1.8%	2019	2019
228,918	0.2%	24	4.3%	4,784,254	1.6%	25	0.0%	11,356,549	1.6%	47,912	2.0%	2020	2020
229,061	0.1%	24	0.0%	4,865,684	1.7%	26	4.0%	11,541,254	1.6%	48,904	2.1%	2021	2021
229,116	0.0%	24	0.0%	4,954,167	1.8%	27	3.8%	11,738,821	1.7%	49,960	2.2%	2022	2022
229,137	0.0%	25	4.2%	5,043,330	1.8%	27	0.0%	11,942,531	1.7%	51,075	2.2%	2023	2023
229,145	0.0%	25	0.0%	5,133,188	1.8%	28	3.7%	12,152,054	1.8%	52,246	2.3%	2024	2024
229,149	0.0%	25	0.0%	5,226,355	1.8%	29	3.6%	12,369,676	1.8%	53,469	2.3%	2025	2025
	0.9%		0.9%		2.1%		3.3%		1.8%		2.0%		

Total Retail Sales		Total Retail Customers	
5,905,862		44,018	
6,000,896	1.6%	44,614	1.4%
6,074,531	1.2%	45,310	1.6%
6,156,745	1.4%	46,090	1.7%
6,246,606	1.5%	46,942	1.8%
6,343,378	1.5%	47,863	2.0%
6,446,508	1.6%	48,854	2.1%
6,555,538	1.7%	49,909	2.2%
6,670,064	1.7%	51,023	2.2%
6,789,720	1.8%	52,193	2.3%
6,914,172	1.8%	53,415	2.3%
	1.6%		2.0%

Year	Month	Actual	Pred	Average Annual Growth	Upper	Lower	Sigma
2007	1	38,345.000					
2007	2	38,464.000					
2007	3	38,420.000					
2007	4	38,582.000					
2007	5	38,534.000					
2007	6	38,629.000					
2007	7	38,440.000					
2007	8	38,383.000					
2007	9	38,317.000					
2007	10	38,423.000					
2007	11	38,613.000					
2007	12	38,632.000					
2008	1	38,730.000					
2008	2	38,722.000	38843.3778		39016.43835	38670.31725	87.02673277
2008	3	38,805.000	38801.71966		38974.67803	38628.76128	86.97535307
2008	4	38,906.000	38931.86928		39104.78879	38758.94976	86.95581224
2008	5	38,877.000	38918.98645		39091.87955	38746.09336	86.94252492
2008	6	38,861.000	38967.08842		39139.86864	38794.3082	86.88576323
2008	7	38,781.000	38853.72521		39026.40345	38681.04697	86.83448295
2008	8	38,774.000	38840.67761		39013.21564	38668.13958	86.76397604
2008	9	38,754.000	38826.08985		38998.53658	38653.64312	86.71806322
2008	10	38,896.000	38893.86565		39066.21516	38721.51614	86.66917421
2008	11	38,890.000	39031.46207		39203.8129	38859.11125	86.66983504
2008	12	39,062.000	39008.89362		39181.15771	38836.62954	86.62621842
2009	1	39,080.000	39130.68971		39302.97281	38958.40661	86.63577936
2009	2	39,097.000	39159.31464		39331.52642	38987.10287	86.59991068
2009	3	39,170.000	39169.7937		39341.9349	38997.6525	86.56442146
2009	4	39,161.000	39245.45995		39417.56337	39073.35654	86.54541811
2009	5	39,162.000	39216.85464		39388.87522	39044.83406	86.50376527
2009	6	39,254.000	39244.28902		39416.23412	39072.34391	86.46580966
2009	7	39,159.000	39236.2817		39408.2013	39064.3621	86.45298391
2009	8	39,113.000	39210.23666		39382.03341	39038.43992	86.3912039
2009	9	39,140.000	39191.48811		39363.19114	39019.78508	86.34407829
2009	10	39,147.000	39259.2583		39430.90603	39087.61058	86.31626737
2009	11	39,324.000	39290.76144		39462.34548	39119.1774	86.28424423
2009	12	39,349.000	39388.53423		39560.13627	39216.9322	86.29329422
2010	1	39,422.000	39412.07365		39583.6216	39240.5257	86.26609321
2010	2	39,439.000	39453.94958		39625.46673	39282.43244	86.25060155
2010	3	39,573.000	39473.14016		39644.60149	39301.67883	86.22253641
2010	4	39,584.000	39534.32907		39705.7881	39362.87004	86.22137744
2010	5	39,550.000	39522.52581		39693.92784	39351.12379	86.19271473
2010	6	39,555.000	39523.62491		39694.95227	39352.29755	86.15516853
2010	7	39,385.000	39483.91841		39655.18982	39312.647	86.12703079
2010	8	39,408.000	39418.75859		39589.90706	39247.61012	86.06520875
2010	9	39,399.000	39438.79278		39609.89741	39267.68815	86.04316269
2010	10	39,403.000	39458.01122		39629.06166	39286.96077	86.01591502
2010	11	39,491.000	39501.2518		39672.25459	39330.24901	85.99195046
2010	12	39,671.000	39545.23424		39716.21961	39374.24886	85.98319409
2011	1	39,638.000	39632.24775		39803.24754	39461.24796	85.99044215

2011	2	39,631.000	39617.52953	39788.47119	39446.58787	85.96121225
2011	3	39,673.000	39637.70705	39808.60154	39466.81255	85.93749074
2011	4	39,647.000	39652.04102	39822.90537	39481.17667	85.92233375
2011	5	39,712.000	39634.37244	39805.18727	39463.55761	85.89743149
2011	6	39,857.000	39671.48962	39842.28327	39500.69596	85.88678406
2011	7	39,693.000	39683.36318	39854.15898	39512.56738	85.88786154
2011	8	39,198.000	39622.60594	39793.3189	39451.89298	85.84620266
2011	9	39,603.000	39438.4135	39608.9793	39267.8477	85.77220316
2011	10	39,589.000	39632.11431	39802.73827	39461.49035	85.80144834
2011	11	39,485.000	39661.23301	39831.82372	39490.6423	85.78472828
2011	12	39,742.000	39659.60762	39830.14956	39489.06567	85.76020497
2012	1	39,750.000	39769.56007	39940.12598	39598.99416	85.77225804
2012	2	39,743.000	39784.76057	39955.30138	39614.21977	85.75963262
2012	3	39,691.000	39809.12221	39979.63683	39638.60759	85.74646398
2012	4	39,799.000	39798.44317	39968.92626	39627.96007	85.73061436
2012	5	39,748.000	39869.27791	40039.75686	39698.79896	85.72852695
2012	6	39,720.000	39889.90066	40060.35216	39719.44916	85.71472312
2012	7	39,804.000	39859.21415	40029.64436	39688.78394	85.70401876
2012	8	39,884.000	39862.35742	40032.78177	39691.93306	85.70107277
2012	9	39,964.000	40006.86217	40177.28051	39836.44384	85.69804692
2012	10	40,102.000	40031.85637	40202.26903	39861.44371	85.69519292
2012	11	40,164.000	40094.27073	40264.6842	39923.85726	85.69560007
2012	12	40,232.000	40178.26853	40348.67485	40007.86221	85.69200433
2013	1	40,232.000	40191.09915	40361.49945	40020.69884	85.68897986
2013	2	40,254.000	40194.05445	40364.44344	40023.66547	85.68328562
2013	3	40,248.000	40204.62855	40375.00956	40034.24755	85.67927364
2013	4	40,169.000	40223.13778	40393.51041	40052.76514	85.67506703
2013	5	40,111.000	40189.11283	40359.476	40018.74966	85.67030479
2013	6	40,138.000	40189.33763	40359.69609	40018.97916	85.66794085
2013	7	40,216.000	40219.65582	40390.01372	40049.29792	85.66765472
2013	8	40,251.000	40257.71046	40428.06909	40087.35182	85.6680247
2013	9	40,273.000	40328.62457	40498.98442	40158.26471	85.66863856
2013	10	40,418.000	40364.22751	40534.5898	40193.86523	85.66986147
2013	11	40,558.000	40438.89806	40609.26152	40268.53459	85.67045399
2013	12	40,591.000	40529.23775	40699.60247	40358.87302	85.67108697
2014	1	40,620.000	40536.68489	40707.05303	40366.31674	85.67280609
2014	2	40,617.000	40555.55573	40725.92849	40385.18298	85.67512656
2014	3	40,589.000	40555.46383	40725.84382	40385.08383	85.67876623
2014	4	40,565.000	40544.94309	40715.33374	40374.55244	85.68412585
2014	5	40,471.000	40536.99068	40707.39425	40366.58711	85.69062225
2014	6	40,521.000	40524.55952	40694.98517	40354.13387	85.70172483
2014	7	40,540.000	40574.12687	40744.56321	40403.69054	85.70709863
2014	8	40,598.000	40598.37114	40768.82253	40427.91975	85.71466933
2014	9	40,686.000	40657.71562	40828.17845	40487.2528	85.72041983
2014	10	40,770.000	40735.32361	40905.79455	40564.85267	85.72449925
2014	11	40,907.000	40797.48475	40967.9646	40627.0049	85.72898107
2014	12	40,930.000	40869.5861	41040.06784	40699.10436	85.72993002
2015	1	40,949.000	40886.02544	41056.52518	40715.5257	85.73898298
2015	2	40,941.000	40901.48747	41072.0071	40730.96784	85.74898404
2015	3	40,903.000	40903.48575	41074.03118	40732.94031	85.76196112

2015	4	40,863.000	40898.17353		41068.75233	40727.59473	85.77873852
2015	5	40,849.000	40885.68858		41056.30403	40715.07314	85.79716596
2015	6	40,907.000	40920.19258		41090.84194	40749.54322	85.81422226
2015	7	40,945.000	40971.5452		41142.21426	40800.87613	85.82413109
2015	8		41018.21931		41188.91335	40847.52526	85.83669163
2015	9		41087.57673		41258.28822	40916.86524	85.84546485
2015	10		41154.74445		41325.47475	40984.01415	85.85492537
2015	11		41224.90839		41395.65853	41054.15826	85.86489814
2015	12		41273.38789		41444.15758	41102.61821	85.87472942
2016	1		41317.33938		41488.13484	41146.54392	85.88769115
2016	2		41355.84574		41526.669	41185.02249	85.90166823
2016	3		41388.13514		41558.98859	41217.2817	85.91685094
2016	4		41420.10423		41590.99065	41249.21782	85.93342841
2016	5		41452.22693		41623.14747	41281.3064	85.95058828
2016	6		41505.12666		41676.08234	41334.17098	85.96826009
2016	7		41554.55042		41725.5356	41383.56524	85.98309484
2016	8		41610.41609		41781.43261	41439.39957	85.99885702
2016	9		41669.44226		41840.48871	41498.39582	86.01390379
2016	10		41730.08839		41901.16432	41559.01246	86.02873008
2016	11		41793.73544		41964.84088	41622.62999	86.04357354
2016	12		41847.47426		42018.60872	41676.33979	86.05816737
2017	1		41899.54435	1.41%	42070.71201	41728.3767	86.07485596
2017	2		41949.331		42120.53315	41778.12885	86.09220202
2017	3		41996.36896		42167.60719	41825.13074	86.11034341
2017	4		42043.55509		42214.83121	41872.27897	86.12939918
2017	5		42091.10379		42262.41853	41919.78905	86.14882196
2017	6		42149.28038		42320.63438	41977.92637	86.16856571
2017	7		42205.99244		42377.38207	42034.6028	86.18648256
2017	8		42266.17818		42437.60467	42094.75168	86.20501873
2017	9		42328.19963		42499.66213	42156.73713	86.22312388
2017	10		42391.28702		42562.7853	42219.78873	86.2411197
2017	11		42456.12674		42627.6609	42284.59258	86.25915823
2017	12		42516.28433		42687.85411	42344.71455	86.27707297
2018	1		42575.86421	1.61%	42747.47228	42404.25615	86.29632371
2018	2		42634.55862		42806.20582	42462.91142	86.31600221
2018	3		42692.13431		42863.82165	42520.44697	86.33618746
2018	4		42750.03346		42921.76207	42578.30484	86.35694508
2018	5		42808.36152		42980.13188	42636.59117	86.37793469
2018	6		42872.23257		43044.04506	42700.42007	86.39912635
2018	7		42935.61934		43107.47181	42763.76687	86.41922861
2018	8		43000.98129		43172.87451	42829.08807	86.4397201
2018	9		43067.50087		43239.43436	42895.56738	86.45997041
2018	10		43134.79312		43306.76679	42962.81946	86.48017338
2018	11		43203.19879		43375.21272	43031.18487	86.50041935
2018	12		43269.51013		43441.56421	43097.45606	86.52060932
2019	1		43335.77115	1.78%	43507.86697	43163.67533	86.54160223
2019	2		43401.82718		43573.96527	43229.68909	86.56285736
2019	3		43467.56069		43639.74165	43295.37972	86.58441799
2019	4		43533.68906		43705.91357	43361.46454	86.60631897
2019	5		43600.26356		43772.53191	43427.99521	86.62835932

2019	6	43669.83136		43842.14378	43497.51895	86.6505202
2019	7	43739.3877		43911.74294	43567.03245	86.67205634
2019	8	43810.1569		43982.55542	43637.75837	86.69382232
2019	9	43881.7303		44054.17184	43709.28876	86.71545449
2019	10	43953.91484		44126.39936	43781.43033	86.73706411
2019	11	44026.87908		44199.40662	43854.35153	86.75870218
2019	12	44099.02329		44271.5938	43926.45277	86.78031148
2020	1	44171.36481	1.93%	44343.97922	43998.75041	86.80237909
2020	2	44243.82537		44416.48395	44071.16679	86.82459486
2020	3	44316.34517		44489.04827	44143.64207	86.84698151
2020	4	44389.2805		44562.02849	44216.53251	86.86955683
2020	5	44462.6557		44635.44873	44289.86267	86.8922058
2020	6	44537.73889		44710.57708	44364.9007	86.91491669
2020	7	44613.03155		44785.91419	44440.1489	86.93727123
2020	8	44689.1426		44862.06995	44516.21526	86.9597483
2020	9	44765.86724		44938.83911	44592.89536	86.98214362
2020	10	44843.10807		45016.12445	44670.0917	87.00451877
2020	11	44920.94795		45094.00883	44747.88706	87.02690138
2020	12	44998.58853		45171.69387	44825.48319	87.04925883
2021	1	45076.53564	2.05%	45249.68593	44903.38535	87.07186016
2021	2	45154.74912		45358.81952	44950.67873	102.6206156
2021	3	45233.19805		45444.5024	45021.89371	106.2583411
2021	4	45312.05884		45525.20746	45098.91022	107.1857693
2021	5	45391.3425		45604.98927	45177.69573	107.4362725
2021	6	45471.67984		45685.4817	45257.87798	107.5142638
2021	7	45552.32301		45766.19174	45338.45427	107.5478939
2021	8	45633.57433		45847.48749	45419.66117	107.5702332
2021	9	45715.33066		45929.28237	45501.37896	107.5896161
2021	10	45797.54237		46011.5311	45583.55365	107.6082311
2021	11	45880.24966		46094.275	45666.22432	107.6266443
2021	12	45963.05362		46177.11543	45748.99182	107.644983
2022	1	46046.20524	2.15%	46261.83246	45830.57803	108.4321773
2022	2	46129.68344		46345.96396	45913.40292	108.7607034
2022	3	46213.47174		46429.94659	45996.99689	108.858424
2022	4	46297.657		46514.20871	46081.10529	108.8970762
2022	5	46382.24366		46598.84208	46165.64523	108.9205696
2022	6	46467.54501		46684.1824	46250.90761	108.9401657
2022	7	46553.18734		46769.8615	46336.51318	108.9586541
2022	8	46639.32028		46856.03071	46422.60986	108.9768895
2022	9	46725.8914		46942.63787	46509.14494	108.9950129
2022	10	46812.87495		47029.65736	46596.09254	109.0130869
2022	11	46900.28993		47117.10822	46683.47165	109.0311297
2022	12	46987.93657		47204.79066	46771.08247	109.049136
2023	1	47075.93891	2.24%	47293.20587	46858.67195	109.2567514
2023	2	47164.28546		47381.73999	46946.83093	109.3510749
2023	3	47252.96701		47470.49619	47035.43784	109.3886136
2023	4	47342.02586		47559.60071	47124.45101	109.4115821
2023	5	47431.46323		47649.07627	47213.85019	109.430788
2023	6	47521.43426		47739.08353	47303.78499	109.4490054
2023	7	47611.75176		47829.4366	47394.06692	109.4668928

2023	8	47702.48932		47920.20956	47484.76909	109.484693
2023	9	47793.61985		48011.37535	47575.86435	109.5024262
2023	10	47885.12956		48102.92023	47667.33889	109.5201113
2023	11	47977.02697		48194.85272	47759.20121	109.5377541
2023	12	48069.21157		48287.07232	47851.35082	109.5553505
2024	1	48161.74425	2.31%	48379.73321	47943.75529	109.6198244
2024	2	48254.61834		48472.67976	48036.55692	109.6562619
2024	3	48347.82831		48565.93418	48129.72245	109.6786108
2024	4	48441.39433		48659.53739	48223.25126	109.6973191
2024	5	48535.31607		48753.49441	48317.13773	109.7150584
2024	6	48629.66994		48847.88299	48411.45689	109.7325145
2024	7	48724.36173		48942.60923	48506.11424	109.7498352
2024	8	48819.42722		49037.70905	48601.1454	109.767097
2024	9	48914.852		49133.16803	48696.53598	109.7842973
2024	10	49010.62831		49228.97844	48792.27819	109.8014422
2024	11	49106.7595		49325.14361	48888.37539	109.8185338
2024	12	49203.1946		49421.61259	48984.77661	109.8355692
2025	1	49299.96307	2.36%	49518.43796	49081.48818	109.8641818
2025	2	49397.0607		49615.5786	49178.54281	109.8858077
2025	3	49494.48389		49713.03776	49275.93002	109.9039001
2025	4	49592.24179		49810.82976	49373.65382	109.9210476
2025	5	49690.33339		49908.95489	49471.71189	109.9379095
2025	6	49788.79591		50007.45071	49570.14111	109.9546549
2025	7	49887.58155		50106.26947	49668.89362	109.9713125
2025	8	49986.70729		50205.42822	49767.98636	109.9879094
2025	9	50086.1651		50304.91891	49867.4113	110.0044409
2025	10	50185.95028		50404.73684	49967.16373	110.0209092
2025	11	50286.06367		50504.88285	50067.24449	110.0373149
2025	12	50386.47903		50605.33071	50167.62736	110.0536562
2026	1	50487.21023	2.41%	50706.10001	50268.32044	110.0728208
2026	2	50588.25434		50807.17869	50369.32998	110.0902043
2026	3	50689.60874		50908.56582	50470.65166	110.1066622
2026	4	50791.2772		51010.26644	50572.28796	110.1228359
2026	5	50893.2584		51112.27956	50674.23724	110.1388872
2026	6	50995.57008		51214.623	50776.51716	110.1548577
2026	7	51098.18763		51317.27216	50879.10311	110.17075
2026	8	51201.11871		51420.23471	50982.00272	110.1865751
2026	9	51304.35854		51523.50586	51085.21122	110.2023295
2026	10	51407.90398		51627.08249	51188.72546	110.2180141
2026	11	51511.75467		51730.96423	51292.5451	110.233629
2026	12	51615.89676		51835.13724	51396.65628	110.249173
2027	1	51720.33639	2.44%	51939.60906	51501.06371	110.2653643
2027	2	51825.07133		52044.37521	51605.76744	110.2810595
2027	3	51930.09951		52149.43404	51710.76498	110.2964704
2027	4	52035.42205		52254.78698	51816.05712	110.3117559
2027	5	52141.03753		52360.43269	51921.64238	110.3269553
2027	6	52246.95406		52466.37928	52027.52883	110.3420784
2027	7	52353.1586		52572.61374	52133.70345	110.3571237
2027	8	52459.65424		52679.13916	52240.16932	110.372096
2027	9	52566.43785		52785.9524	52346.92331	110.3869931

2027	10	52673.50715		52893.05117	52453.96313	110.4018155
2027	11	52780.8612		53000.43455	52561.28786	110.4165629
2027	12	52888.4924		53108.09492	52668.88988	110.4312349
2028	1	52996.40307	2.47%	53216.03497	52776.77116	110.4460104
2028	2	53104.59137		53324.2523	52884.93045	110.460605
2028	3	53213.05558		53432.74528	52993.36589	110.4750711
2028	4	53321.79553		53541.51381	53102.07724	110.4894479
2028	5	53430.80981		53650.55652	53211.06309	110.5037446
2028	6	53540.10174		53759.87673	53320.32675	110.5179636
2028	7	53649.66415		53869.46726	53429.86104	110.5321032
2028	8	53759.49787		53979.32894	53539.6668	110.5461657
2028	9	53869.60065		54089.45953	53649.74177	110.5601498
2028	10	53979.97066		54199.85719	53760.08412	110.5740557
2028	11	54090.60675		54310.52079	53870.69272	110.5878834
2028	12	54201.50446		54421.44583	53981.56308	110.6016323
2029	1	54312.66426	2.48%	54532.6329	54092.69561	110.6153476
2029	2	54424.08456		54644.08028	54204.08885	110.6289581
2029	3	54535.76384		54755.78644	54315.74124	110.6424767
2029	4	54647.70134		54867.75066	54427.65203	110.655913
2029	5	54759.8957		54979.97158	54539.81983	110.6692692
2029	6	54872.34793		55092.4502	54652.24565	110.6825457
2029	7	54985.05377		55205.18229	54764.92525	110.6957414
2029	8	55098.01301		55318.16761	54877.85841	110.7088575
2029	9	55211.22387		55431.40439	54991.04334	110.7218933
2029	10	55324.68479		55544.89107	55104.4785	110.7348489
2029	11	55438.39456		55658.62646	55218.16267	110.7477243
2029	12	55552.35033		55772.60766	55332.09299	110.7605192
2030	1	55666.55168	2.49%	55886.83432	55446.26904	110.7732451
2030	2	55780.99721		56001.30498	55560.68943	110.7858842
2030	3	55895.68551		56116.01826	55675.35277	110.7984395
2030	4	56010.61561		56230.97315	55790.25806	110.8109136
2030	5	56125.78618		56346.16837	55905.40399	110.8233067
2030	6	56241.19712		56461.6038	56020.79044	110.835619
2030	7	56356.8457		56577.2767	56136.41471	110.8478499
2030	8	56472.7312		56693.18636	56252.27604	110.86
2030	9	56588.85213		56809.33129	56368.37297	110.8720691
2030	10	56705.2071		56925.7101	56484.7041	110.8840571
2030	11	56821.79492		57042.3216	56601.26824	110.8959642
2030	12	56938.61356		57159.16376	56718.06336	110.9077902
2031	1	57055.66223	2.50%	57276.23579	56835.08867	110.9195381
2031	2	57172.93963		57393.53638	56952.34287	110.9312035
2031	3	57290.44448		57511.06427	57069.82469	110.9427872
2031	4	57408.1757		57628.81837	57187.53304	110.9542897
2031	5	57526.13207		57746.79745	57305.46669	110.9657112
2031	6	57644.31294		57865.00087	57423.62501	110.9770518
2031	7	57762.71639		57983.42671	57542.00607	110.9883112
2031	8	57881.34148		58102.07403	57660.60893	110.9994897
2031	9	58000.18691		58220.94152	57779.43229	111.0105873
2031	10	58119.25141		58340.02794	57898.47489	111.021604
2031	11	58238.53384		58459.33211	58017.73557	111.03254

2031	12	58358.03261		58578.85247	58137.21276	111.0433953
2032	1	58477.74679	2.49%	58698.58808	58256.90551	111.0541707
2032	2	58597.67518		58818.53773	58376.81262	111.0648652
2032	3	58717.81658		58938.70024	58496.93292	111.0754791
2032	4	58838.16991		59059.07452	58617.2653	111.0860125
2032	5	58958.73402		59179.65941	58737.80863	111.0964656
2032	6	59079.50805		59300.45407	58858.56203	111.1068385
2032	7	59200.49049		59421.45698	58979.524	111.117131
2032	8	59321.68036		59542.66716	59100.69356	111.1273436
2032	9	59443.07646		59664.08341	59222.06951	111.1374762
2032	10	59564.67764		59785.70458	59343.6507	111.1475289
2032	11	59686.4828		59907.52957	59465.43603	111.1575018
2032	12	59808.49064		60029.55708	59587.42419	111.1673952
2033	1	59930.70015	2.48%	60151.78611	59709.61419	111.1772093
2033	2	60053.11024		60274.21556	59832.00492	111.1869439
2033	3	60175.71978		60396.8443	59954.59526	111.1965993
2033	4	60298.52773		60519.67129	60077.38417	111.2061756
2033	5	60421.53301		60642.69546	60200.37056	111.215673
2033	6	60544.73467		60765.91585	60323.55349	111.2250915
2033	7	60668.13148		60889.33123	60446.93173	111.2344313
2033	8	60791.72243		61012.94059	60570.50426	111.2436925
2033	9	60915.50643		61136.74286	60694.27	111.2528754
2033	10	61039.48241		61260.73695	60818.22788	111.26198
2033	11	61163.64934		61384.92182	60942.37685	111.2710066
2033	12	61288.00607		61509.29635	61066.71579	111.2799553
2034	1	61412.55162	2.47%	61633.85954	61191.2437	111.2888263
2034	2	61537.28495		61758.61036	61315.95954	111.2976198
2034	3	61662.20503		61883.54777	61440.86229	111.3063358
2034	4	61787.31086		62008.67078	61565.95094	111.3149747
2034	5	61912.60141		62133.97836	61691.22447	111.3235365
2034	6	62038.07576		62259.46957	61816.68194	111.3320215
2034	7	62163.7328		62385.14333	61942.32226	111.3404299
2034	8	62289.57157		62510.99867	62068.14446	111.3487617
2034	9	62415.59106		62637.03458	62194.14753	111.3570173
2034	10	62541.79027		62763.25007	62320.33048	111.3651967
2034	11	62668.16824		62889.64414	62446.69233	111.3733003

2034	12	62794.72392		63016.21579	62573.23205	111.3813282
2035	1	62921.45638	2.46%	63142.96406	62699.94869	111.3892806
2035	2	63048.36464		63269.88798	62826.84129	111.3971578
2035	3	63175.44773		63396.9866	62953.90887	111.4049599
2035	4	63302.70472		63524.25895	63081.15049	111.4126871
2035	5	63430.13464		63651.70409	63208.5652	111.4203397
2035	6	63557.73659		63779.32111	63336.15208	111.4279178
2035	7	63685.50958		63907.10902	63463.91014	111.4354217
2035	8	63813.45269		64035.06691	63591.83848	111.4428516
2035	9	63941.56498		64163.19382	63719.93614	111.4502077
2035	10	64069.84552		64291.48885	63848.2022	111.4574903
2035	11	64198.2934		64419.95106	63976.63574	111.4646995
2035	12	64326.90766		64548.57951	64105.23581	111.4718357
2036	1	64455.68742	2.44%	64677.37331	64234.00152	111.4788989
2036	2	64584.63176		64806.33156	64362.93196	111.4858896
2036	3	64713.73978		64935.45334	64492.02623	111.4928078
2036	4	64843.0106		65064.73777	64621.28343	111.4996538
2036	5	64972.44331		65194.18395	64750.70267	111.5064279
2036	6	65102.03705		65323.79102	64880.28308	111.5131304
2036	7	65231.79091		65453.55807	65010.02376	111.5197613
2036	8	65361.70403		65583.48423	65139.92383	111.526321
2036	9	65491.77553		65713.56864	65269.98243	111.5328098
2036	10	65622.00454		65843.81041	65400.19867	111.5392278
2036	11	65752.3902		65974.20869	65530.57171	111.5455753
2036	12	65882.93163		66104.7626	65661.10066	111.5518526
2037	1	66013.628	2.42%	66235.47131	65791.78468	111.5580599
2037	2	66144.47844		66366.33396	65922.62292	111.5641974
2037	3	66275.48212		66497.34971	66053.61453	111.5702655
2037	4	66406.6382		66628.51772	66184.75868	111.5762643
2037	5	66537.94584		66759.83715	66316.05453	111.5821942
2037	6	66669.40423		66891.30719	66447.50126	111.5880553
2037	7	66801.01252		67022.927	66579.09803	111.593848
2037	8	66932.76989		67154.69576	66710.84402	111.5995725
2037	9	67064.67553		67286.61265	66842.73842	111.6052289
2037	10	67196.72863		67418.67686	66974.7804	111.6108177
2037	11	67328.92838		67550.88759	67106.96917	111.6163391
2037	12	67461.27396		67683.24401	67239.3039	111.6217933
2038	1	67593.76458	2.39%	67815.74535	67371.78381	111.6271806
2038	2	67726.39945		67948.3908	67504.4081	111.6325012
2038	3	67859.17778		68081.17957	67637.17598	111.6377555
2038	4	67992.09877		68214.11088	67770.08665	111.6429436
2038	5	68125.16165		68347.18395	67903.13935	111.6480659
2038	6	68258.36565		68480.39801	68036.33329	111.6531226
2038	7	68391.70998		68613.75226	68169.6677	111.658114
2038	8	68525.19388		68747.24596	68303.1418	111.6630404
2038	9	68658.81659		68880.87833	68436.75484	111.6679019
2038	10	68792.57733		69014.64862	68570.50605	111.672699
2038	11	68926.47536		69148.55606	68704.39467	111.6774318
2038	12	69060.50992		69282.59991	68838.41994	111.6821006
			2.26%			

Table 4.
Population and Housing Units: 1970 to 2010

[For information concerning historical counts and geographic change, see "User Notes." For information on confidentiality, nonsampling error, and definitions, see Appendixes]

State County/County Equivalent	Population					Housing units				
	2010	2000	1990	1980	1970	2010	2000	1990	1980	1970
Minnesota	**5,303,925 r**	**4,919,492**	**4,375,665**	**4,075,970**	**3,806,103**	**2,347,201 r**	**2,065,952**	**1,848,566**	**1,612,960**	**1,276,552**
Aitkin County	16,202	15,301	12,425	13,404	11,403	16,029	14,168	12,934	11,124	7,798
Anoka County	330,844	298,084	243,641	195,998	154,712	126,688	108,091	85,519	62,904	40,857
Becker County	32,504	30,000	27,881	29,336	24,372	18,784	16,612	15,563	15,430	10,912
Beltrami County	44,442	39,650	34,384	30,982	26,373	20,527	16,989	14,670	13,099	9,590
Benton County	38,451 r	34,227	30,185	25,187	20,841	16,140 r	13,461	11,521	8,812	6,018
Big Stone County	5,269	5,820	6,285	7,716	7,941	3,115	3,171	3,192	3,493	3,024
Blue Earth County	64,013	55,941	54,044	52,314	52,322	26,202	21,971	20,358	19,381	15,767
Brown County	25,893	26,911	26,984	28,645	28,887	11,493	11,163	10,814	10,469	9,070
Carlton County	35,386	31,671	29,259	29,936	28,072	15,656	13,721	12,342	11,782	9,044
Carver County	91,042	70,205	47,915	37,046	28,331	34,536	24,883	17,449	12,585	8,266
Cass County	28,567	27,150	21,791	21,050	17,323	24,903	21,286	18,863	17,586	11,004
Chippewa County	12,441	13,088	13,228	14,941	15,109	5,721	5,855	5,755	6,120	5,308
Chisago County	53,887	41,101	30,521	25,717	17,492	21,172	15,533	11,946	9,561	6,430
Clay County	58,999	51,229	50,422	49,327	46,608	23,959	19,746	18,546	17,811	13,950
Clearwater County	8,695	8,423	8,309	8,761	8,013	4,773	4,114	4,008	3,824	3,167
Cook County	5,176	5,168	3,868	4,092	3,423	5,839	4,708	4,312	3,456	2,360
Cottonwood County	11,687	12,167	12,694	14,854	14,887	5,412	5,376	5,495	5,804	5,130
Crow Wing County	62,500	55,099	44,249	41,722	34,826	40,180	33,483	29,916	25,688	19,799
Dakota County	398,552	355,904	275,189	194,279	139,808	159,598	133,750	102,685	66,872	39,224
Dodge County	20,087	17,731	15,731	14,773	13,037	7,947	6,642	5,771	5,531	4,128
Douglas County	36,009	32,821	28,674	27,839	22,910	19,905	16,694	14,590	13,179	9,073
Faribault County	14,553	16,181	16,937	19,714	20,896	7,090	7,247	7,416	7,950	7,232
Fillmore County	20,866	21,122	20,777	21,930	21,916	9,732	8,908	8,356	8,445	7,637
Freeborn County	31,255	32,584	33,060	36,329	38,064	14,231	13,996	13,783	13,815	12,412
Goodhue County	46,183	44,127	40,690	38,749	34,804	20,337	17,879	15,936	14,368	11,436
Grant County	6,018	6,289	6,246	7,171	7,462	3,324	3,098	3,178	3,192	2,908
Hennepin County	1,152,425 r	1,116,039	1,032,431	941,411	960,080	509,469 r	468,826	443,583	379,503	320,479
Houston County	19,027	19,718	18,497	18,382	17,556	8,601	8,168	7,257	6,673	5,486
Hubbard County	20,428	18,376	14,939	14,098	10,583	14,622	12,229	10,042	9,103	6,062
Isanti County	37,816	31,287	25,921	23,600	16,560	15,321	12,062	9,693	8,372	5,574
Itasca County	45,058	43,992	40,863	43,069	35,530	27,065	24,528	22,494	21,221	14,944
Jackson County	10,266	11,268	11,677	13,690	14,352	4,990	5,092	5,121	5,525	4,918
Kanabec County	16,239	14,996	12,802	12,161	9,775	7,849	6,846	6,098	5,485	3,735
Kandiyohi County	42,239	41,203	38,761	36,763	30,548	19,476	18,415	16,669	15,100	11,109
Kittson County	4,552	5,285	5,767	6,672	6,853	2,605	2,719	2,865	3,018	2,747
Koochiching County	13,311	14,355	16,299	17,571	17,131	7,900	7,719	7,825	7,241	6,277
Lac qui Parle County	7,259	8,067	8,924	10,592	11,164	3,692	3,774	3,955	4,272	3,984
Lake County	10,866	11,058	10,415	13,043	13,351	7,681	6,840	6,776	6,110	4,942
Lake of the Woods County	4,045	4,522	4,076	3,764	3,987	3,672	3,238	3,050	2,709	1,730
Le Sueur County	27,703	25,426	23,239	23,434	21,332	12,416	10,858	9,785	9,509	7,672
Lincoln County	5,896	6,429	6,890	8,207	8,143	3,108	3,043	3,050	3,298	2,882
Lyon County	25,857	25,425	24,789	25,207	24,273	11,098	10,298	9,675	9,196	7,526
McLeod County	36,651	34,898	32,030	29,657	27,662	15,760	14,087	12,391	10,916	8,767
Mahnomen County	5,413	5,190	5,044	5,535	5,638	2,786	2,700	2,505	2,410	2,148
Marshall County	9,439	10,155	10,993	13,027	13,060	4,812	4,791	5,049	5,253	4,660
Martin County	20,840	21,802	22,914	24,687	24,316	10,009	9,800	9,847	9,784	8,451
Meeker County	23,300	22,644	20,846	20,594	18,387	10,674	9,821	9,139	8,539	6,598
Mille Lacs County	26,097	22,330	18,670	18,430	15,703	12,750	10,467	9,065	8,290	6,055
Morrison County	33,198	31,712	29,604	29,311	26,949	15,731	13,870	12,434	11,619	9,055
Mower County	39,163	38,603	37,385	40,390	44,919	17,027	16,251	15,831	15,679	14,364
Murray County	8,725	9,165	9,660	11,507	12,508	4,556	4,357	4,611	4,679	4,236
Nicollet County	32,727	29,771	28,076	26,929	24,518	12,873	11,240	9,963	8,959	6,843
Nobles County	21,378	20,832	20,098	21,840	23,208	8,535	8,465	8,094	8,212	7,386
Norman County	6,852	7,442	7,975	9,379	10,008	3,421	3,455	3,648	4,018	3,722
Olmsted County	144,248	124,277	106,470	92,006	84,104	60,495	49,422	41,603	34,345	26,639
Otter Tail County	57,303	57,159	50,714	51,937	46,097	35,594	33,862	29,295	26,953	20,486
Pennington County	13,930	13,584	13,306	15,258	13,266	6,297	6,033	5,682	5,981	4,451
Pine County	29,750	26,530	21,264	19,871	16,821	17,276	15,353	12,738	10,299	7,102
Pipestone County	9,596	9,895	10,491	11,690	12,791	4,483	4,434	4,387	4,636	4,286
Polk County	31,600	31,369	32,589	34,844	34,435	14,610	14,008	14,317	14,766	12,343
Pope County	10,995	11,236	10,745	11,657	11,107	6,435	5,827	5,836	5,658	4,500
Ramsey County	508,640 r	511,202	485,783	459,784	476,255	217,197	206,448	201,022	176,995	153,623
Red Lake County	4,089	4,299	4,525	5,471	5,388	1,948	1,883	1,899	2,041	1,675
Redwood County	16,059	16,815	17,254	19,341	20,024	7,272	7,230	7,144	7,388	6,718
Renville County	15,730	17,154	17,673	20,401	21,139	7,355	7,413	7,442	7,905	7,190
Rice County	64,142	56,665	49,183	46,087	41,582	24,453	20,061	17,520	15,667	12,330
Rock County	9,687	9,721	9,806	10,703	11,346	4,262	4,137	3,963	4,095	3,680
Roseau County	15,629	16,338	15,026	12,574	11,569	7,469	7,101	6,236	5,034	3,983
St. Louis County	200,226	200,528	198,213	222,229	220,693	103,058	95,800	95,403	95,324	80,859
Scott County	129,928	89,498	57,846	43,784	32,423	47,124	31,609	20,302	14,187	8,789
Sherburne County	88,499 r	64,415	41,945	29,908	18,344	32,379	22,827	14,964	10,338	6,448
Sibley County	15,226	15,356	14,366	15,448	15,845	6,582	6,024	5,625	5,628	4,991
Stearns County	150,642 r	133,167	119,324	108,161	95,400	61,974 r	50,292	43,915	35,961	26,089
Steele County	36,576	33,680	30,729	30,328	26,931	15,343	13,306	11,840	11,255	8,758

Table 4.
Population and Housing Units: 1970 to 2010—Con.

[For information concerning historical counts and geographic change, see "User Notes." For information on confidentiality, nonsampling error, and definitions, see Appendixes]

State County/County Equivalent	Population					Housing units				
	2010	2000	1990	1980	1970	2010	2000	1990	1980	1970
Stevens County	9,726	10,053	10,634	11,322	11,218	4,160	4,074	4,108	4,222	3,594
Swift County	9,783	11,956	10,724	12,920	13,177	4,835	4,821	4,795	5,182	4,717
Todd County	24,895	24,426	23,363	24,991	22,114	12,917	11,900	11,234	10,691	8,253
Traverse County	3,558	4,134	4,463	5,542	6,254	2,073	2,199	2,220	2,409	2,298
Wabasha County	21,676	21,610	19,744	19,335	17,224	9,997	9,066	8,205	7,604	5,827
Wadena County	13,843	13,713	13,154	14,192	12,412	6,899	6,334	5,801	5,438	4,280
Waseca County	19,136	19,526	18,079	18,448	16,663	7,903	7,427	7,011	6,884	5,406
Washington County	238,136	201,130	145,858	113,571	83,003	92,374	73,635	51,634	37,182	22,765
Watonwan County	11,211	11,876	11,682	12,361	13,298	5,047	5,036	4,886	4,949	4,583
Wilkin County	6,576	7,138	7,516	8,454	9,389	3,078	3,105	3,140	3,285	3,041
Winona County	51,461	49,985	47,828	46,256	44,409	20,760	19,551	17,630	16,503	13,682
Wright County	124,700 r	89,993	68,710	58,681	38,933	49,000 r	34,357	26,353	21,795	14,238
Yellow Medicine County	10,438	11,080	11,684	13,653	14,523	4,760	4,873	4,983	5,386	5,032

Table 5.

Population, Housing Units, Land Area, and Density: 2010; and Percent Change: 1980 to 2010

[For information concerning historical counts and geographic change, see "User Notes." For information on confidentiality, nonsampling error, and definitions, see Appendixes]

State County/County Equivalent	Population	Housing units	Land area in square miles	Average per square mile of land: Population density	Housing unit density	Percent change: Population 2000 to 2010	Population 1990 to 2000	Population 1980 to 1990	Housing units 2000 to 2010	Housing units 1990 to 2000	Housing units 1980 to 1990
Minnesota	**5,303,925**	**2,347,201**	**79,626.74**	**66.6**	**29.5**	**7.8**	**12.4**	**7.4**	**13.6**	**11.8**	**14.6**
Aitkin County	16,202	16,029	1,821.66	8.9	8.8	5.9	23.1	–7.3	13.1	9.5	16.3
Anoka County	330,844	126,688	423.01	782.1	299.5	11.0	22.3	24.3	17.2	26.4	36.0
Becker County	32,504	18,784	1,315.20	24.7	14.3	8.3	7.6	–5.0	13.1	6.7	0.9
Beltrami County	44,442	20,527	2,504.94	17.7	8.2	12.1	15.3	11.0	20.8	15.8	12.0
Benton County	38,451	16,140	408.30	94.2	39.5	12.3	13.4	19.8	19.9	16.8	30.7
Big Stone County	5,269	3,115	499.02	10.6	6.2	–9.5	–7.4	–18.5	–1.8	–0.7	–8.6
Blue Earth County	64,013	26,202	747.84	85.6	35.0	14.4	3.5	3.3	19.3	7.9	5.0
Brown County	25,893	11,493	611.09	42.4	18.8	–3.8	–0.3	–5.8	3.0	3.2	3.3
Carlton County	35,386	15,656	861.38	41.1	18.2	11.7	8.2	–2.3	14.1	11.2	4.8
Carver County	91,042	34,536	354.33	256.9	97.5	29.7	46.5	29.3	38.8	42.6	38.6
Cass County	28,567	24,903	2,021.54	14.1	12.3	5.2	24.6	3.5	17.0	12.8	7.3
Chippewa County	12,441	5,721	581.12	21.4	9.8	–4.9	–1.1	–11.5	–2.3	1.7	–6.0
Chisago County	53,887	21,172	414.86	129.9	51.0	31.1	34.7	18.7	36.3	30.0	24.9
Clay County	58,999	23,959	1,045.37	56.4	22.9	15.2	1.6	2.2	21.3	6.5	4.1
Clearwater County	8,695	4,773	998.94	8.7	4.8	3.2	1.4	–5.2	16.0	2.6	4.8
Cook County	5,176	5,839	1,452.28	3.6	4.0	0.2	33.6	–5.5	24.0	9.2	24.8
Cottonwood County	11,687	5,412	638.61	18.3	8.5	–3.9	–4.2	–14.5	0.7	–2.2	–5.3
Crow Wing County	62,500	40,180	999.09	62.6	40.2	13.4	24.5	6.1	20.0	11.9	16.5
Dakota County	398,552	159,598	562.17	709.0	283.9	12.0	29.3	41.6	19.3	30.3	53.6
Dodge County	20,087	7,947	439.28	45.7	18.1	13.3	12.7	6.5	19.6	15.1	4.3
Douglas County	36,009	19,905	637.30	56.5	31.2	9.7	14.5	3.0	19.2	14.4	10.7
Faribault County	14,553	7,090	712.48	20.4	10.0	–10.1	–4.5	–14.1	–2.2	–2.3	–6.7
Fillmore County	20,866	9,732	861.30	24.2	11.3	–1.2	1.7	–5.3	9.3	6.6	–1.1
Freeborn County	31,255	14,231	707.09	44.2	20.1	–4.1	–1.4	–9.0	1.7	1.5	–0.2
Goodhue County	46,183	20,337	756.84	61.0	26.9	4.7	8.4	5.0	13.7	12.2	10.9
Grant County	6,018	3,324	548.16	11.0	6.1	–4.3	0.7	–12.9	7.3	–2.5	–0.4
Hennepin County	1,152,425	509,469	553.59	2,081.7	920.3	3.3	8.1	9.7	8.7	5.7	16.9
Houston County	19,027	8,601	552.06	34.5	15.6	–3.5	6.6	0.6	5.3	12.6	8.8
Hubbard County	20,428	14,622	925.67	22.1	15.8	11.2	23.0	6.0	19.6	21.8	10.3
Isanti County	37,816	15,321	435.79	86.8	35.2	20.9	20.7	9.8	27.0	24.4	15.8
Itasca County	45,058	27,065	2,667.72	16.9	10.1	2.4	7.7	–5.1	10.3	9.0	6.0
Jackson County	10,266	4,990	702.98	14.6	7.1	–8.9	–3.5	–14.7	–2.0	–0.6	–7.3
Kanabec County	16,239	7,849	521.59	31.1	15.0	8.3	17.1	5.3	14.7	12.3	11.2
Kandiyohi County	42,239	19,476	796.78	53.0	24.4	2.5	6.3	5.4	5.8	10.5	10.4
Kittson County	4,552	2,605	1,098.80	4.1	2.4	–13.9	–8.4	–13.6	–4.2	–5.1	–5.1
Koochiching County	13,311	7,900	3,104.07	4.3	2.5	–7.3	–11.9	–7.2	2.3	–1.4	8.1
Lac qui Parle County	7,259	3,692	765.02	9.5	4.8	–10.0	–9.6	–15.7	–2.2	–4.6	–7.4
Lake County	10,866	7,681	2,109.29	5.2	3.6	–1.7	6.2	–20.1	12.3	0.9	10.9
Lake of the Woods County	4,045	3,672	1,297.87	3.1	2.8	–10.5	10.9	8.3	13.4	6.2	12.6
Le Sueur County	27,703	12,416	448.76	61.7	27.7	9.0	9.4	–0.8	14.3	11.0	2.9
Lincoln County	5,896	3,108	536.76	11.0	5.8	–8.3	–6.7	–16.0	2.1	–0.2	–7.5
Lyon County	25,857	11,098	714.56	36.2	15.5	1.7	2.6	–1.7	7.8	6.4	5.2
McLeod County	36,651	15,760	491.47	74.6	32.1	5.0	9.0	8.0	11.9	13.7	13.5
Mahnomen County	5,413	2,786	557.88	9.7	5.0	4.3	2.9	–8.9	3.2	7.8	3.9
Marshall County	9,439	4,812	1,775.07	5.3	2.7	–7.1	–7.6	–15.6	0.4	–5.1	–3.9
Martin County	20,840	10,009	712.35	29.3	14.1	–4.4	–4.9	–7.2	2.1	–0.5	0.6
Meeker County	23,300	10,674	608.18	38.3	17.6	2.9	8.6	1.2	8.7	7.5	7.0
Mille Lacs County	26,097	12,750	572.31	45.6	22.3	16.9	19.6	1.3	21.8	15.5	9.3
Morrison County	33,198	15,731	1,125.06	29.5	14.0	4.7	7.1	1.0	13.4	11.5	7.0
Mower County	39,163	17,027	711.33	55.1	23.9	1.5	3.3	–7.4	4.8	2.7	1.0
Murray County	8,725	4,556	704.70	12.4	6.5	–4.8	–5.1	–16.1	4.6	–5.5	–1.5
Nicollet County	32,727	12,873	448.49	73.0	28.7	9.9	6.0	4.3	14.5	12.8	11.2
Nobles County	21,378	8,535	715.11	29.9	11.9	2.6	3.7	–8.0	0.8	4.6	–1.4
Norman County	6,852	3,421	872.79	7.9	3.9	–7.9	–6.7	–15.0	–1.0	–5.3	–9.2
Olmsted County	144,248	60,495	653.35	220.8	92.6	16.1	16.7	15.7	22.4	18.8	21.1
Otter Tail County	57,303	35,594	1,972.07	29.1	18.0	0.3	12.7	–2.4	5.1	15.6	8.7
Pennington County	13,930	6,297	616.57	22.6	10.2	2.5	2.1	–12.8	4.4	6.2	–5.0
Pine County	29,750	17,276	1,411.29	21.1	12.2	12.1	24.8	7.0	12.5	20.5	23.7
Pipestone County	9,596	4,483	465.05	20.6	9.6	–3.0	–5.7	–10.3	1.1	1.1	–5.4
Polk County	31,600	14,610	1,971.13	16.0	7.4	0.7	–3.7	–6.5	4.3	–2.2	–3.0

Table 5.

Population, Housing Units, Land Area, and Density: 2010; and Percent Change: 1980 to 2010—Con.

[For information concerning historical counts and geographic change, see "User Notes." For information on confidentiality, nonsampling error, and definitions, see Appendixes]

State County/County Equivalent	Population	Housing units	Land area in square miles	Average per square mile of land: Population density	Average per square mile of land: Housing unit density	Percent change: Population 2000 to 2010	Percent change: Population 1990 to 2000	Percent change: Population 1980 to 1990	Percent change: Housing units 2000 to 2010	Percent change: Housing units 1990 to 2000	Percent change: Housing units 1980 to 1990
Pope County	10,995	6,435	669.71	16.4	9.6	–2.1	4.6	–7.8	10.4	–0.2	3.1
Ramsey County	508,640	217,197	152.21	3,341.7	1,427.0	–0.5	5.2	5.7	5.2	2.7	13.6
Red Lake County	4,089	1,948	432.41	9.5	4.5	–4.9	–5.0	–17.3	3.5	–0.8	–7.0
Redwood County	16,059	7,272	878.57	18.3	8.3	–4.5	–2.5	–10.8	0.6	1.2	–3.3
Renville County	15,730	7,355	982.91	16.0	7.5	–8.3	–2.9	–13.4	–0.8	–0.4	–5.9
Rice County	64,142	24,453	495.68	129.4	49.3	13.2	15.2	6.7	21.9	14.5	11.8
Rock County	9,687	4,262	482.45	20.1	8.8	–0.3	–0.9	–8.4	3.0	4.4	–3.2
Roseau County	15,629	7,469	1,671.60	9.3	4.5	–4.3	8.7	19.5	5.2	13.9	23.9
St. Louis County	200,226	103,058	6,247.40	32.0	16.5	–0.2	1.2	–10.8	7.6	0.4	0.1
Scott County	129,928	47,124	356.48	364.5	132.2	45.2	54.7	32.1	49.1	55.7	43.1
Sherburne County	88,499	32,379	432.92	204.4	74.8	37.4	53.6	40.2	41.8	52.5	44.7
Sibley County	15,226	6,582	588.78	25.9	11.2	–0.8	6.9	–7.0	9.3	7.1	–0.1
Stearns County	150,642	61,974	1,343.13	112.2	46.1	13.1	11.6	10.3	23.2	14.5	22.1
Steele County	36,576	15,343	429.65	85.1	35.7	8.6	9.6	1.3	15.3	12.4	5.2
Stevens County	9,726	4,160	563.60	17.3	7.4	–3.3	–5.5	–6.1	2.1	–0.8	–2.7
Swift County	9,783	4,835	742.08	13.2	6.5	–18.2	11.5	–17.0	0.3	0.5	–7.5
Todd County	24,895	12,917	944.98	26.3	13.7	1.9	4.5	–6.5	8.5	5.9	5.1
Traverse County	3,558	2,073	573.90	6.2	3.6	–13.9	–7.4	–19.5	–5.7	–0.9	–7.8
Wabasha County	21,676	9,997	522.98	41.4	19.1	0.3	9.5	2.1	10.3	10.5	7.9
Wadena County	13,843	6,899	536.27	25.8	12.9	0.9	4.2	–7.3	8.9	9.2	6.7
Waseca County	19,136	7,903	423.36	45.2	18.7	–2.0	8.0	–2.0	6.4	5.9	1.8
Washington County	238,136	92,374	384.28	619.7	240.4	18.4	37.9	28.4	25.4	42.6	38.9
Watonwan County	11,211	5,047	434.95	25.8	11.6	–5.6	1.7	–5.5	0.2	3.1	–1.3
Wilkin County	6,576	3,078	750.96	8.8	4.1	–7.9	–5.0	–11.1	–0.9	–1.1	–4.4
Winona County	51,461	20,760	626.21	82.2	33.2	3.0	4.5	3.4	6.2	10.9	6.8
Wright County	124,700	49,000	661.46	188.5	74.1	38.6	31.0	17.1	42.6	30.4	20.9
Yellow Medicine County	10,438	4,760	759.10	13.8	6.3	–5.8	–5.2	–14.4	–2.3	–2.2	–7.5

POPULATION ESTIMATES	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Minnesota	4,375,099	4,416,292	4,469,450	4,515,118	4,570,355	4,626,514	4,682,748	4,735,830	4,782,264	4,838,398
Aitkin County	12,425	12,405	12,528	12,593	12,951	13,366	13,739	13,949	14,099	14,235
Anoka County	243,641	248,677	255,064	261,814	266,713	272,636	278,531	285,271	290,871	297,776
Becker County	27,881	27,920	28,189	28,383	28,830	29,163	29,247	29,394	29,582	29,779
Beltrami County	34,384	34,703	35,263	35,360	36,090	36,508	36,972	37,615	37,899	38,644
Benton County	30,185	31,071	31,736	32,306	32,743	33,362	33,707	34,057	34,431	35,110
Big Stone County	6,285	6,226	6,148	6,089	6,025	6,026	5,941	5,915	5,875	5,794
Blue Earth County	54,044	54,194	54,481	54,473	54,995	55,172	55,335	55,286	55,611	55,877
Brown County	26,984	26,999	27,113	27,299	27,359	27,580	27,895	28,006	27,976	28,012
Carlton County	29,259	29,230	29,627	30,003	30,194	30,559	30,776	30,974	31,496	31,591
Carver County	47,915	49,312	50,914	52,758	55,025	57,010	59,183	61,377	63,358	66,168
Cass County	21,791	21,903	22,312	22,562	22,996	23,801	24,107	24,531	24,997	25,644
Chippewa County	13,228	13,162	13,156	13,116	13,123	13,097	13,155	13,183	13,053	13,152
Chisago County	30,521	31,363	32,232	33,255	34,700	36,045	37,269	38,937	40,237	42,041
Clay County	50,422	50,548	51,006	51,261	52,148	52,540	52,895	52,994	53,183	53,322
Clearwater County	8,309	8,276	8,343	8,382	8,371	8,452	8,482	8,467	8,423	8,392
Cook County	3,868	3,880	3,931	4,015	4,088	4,166	4,313	4,437	4,501	4,595
Cottonwood County	12,694	12,634	12,656	12,649	12,732	12,768	12,793	12,930	12,923	12,773
Crow Wing County	44,249	44,964	45,772	46,512	47,299	48,437	49,560	50,578	51,605	52,698
Dakota County	275,227	282,632	290,443	298,679	308,002	316,272	325,079	332,657	339,256	347,245
Dodge County	15,731	15,884	16,083	16,275	16,511	16,680	16,926	17,122	17,298	17,504
Douglas County	28,674	28,849	29,058	29,544	29,971	30,424	30,927	31,274	31,481	31,800
Faribault County	16,937	16,857	16,774	16,685	16,655	16,661	16,614	16,548	16,432	16,364
Fillmore County	20,777	20,846	20,811	20,812	20,799	20,906	20,916	20,969	20,967	20,914
Freeborn County	33,060	33,030	32,979	33,026	32,973	32,759	32,698	32,429	32,324	32,238
Goodhue County	40,690	40,929	41,391	41,681	42,053	42,477	42,742	42,987	43,266	43,469
Grant County	6,246	6,229	6,216	6,196	6,169	6,242	6,220	6,185	6,201	6,165
Hennepin County	1,032,431	1,039,099	1,047,206	1,051,426	1,056,673	1,063,631	1,070,709	1,075,907	1,081,875	1,089,024
Houston County	18,497	18,567	18,757	18,772	18,929	19,123	19,245	19,330	19,412	19,545
Hubbard County	14,939	15,056	15,330	15,517	15,705	16,225	16,440	16,717	16,905	17,177
Isanti County	25,921	26,516	26,992	27,567	28,037	28,664	29,110	29,603	30,038	30,826
Itasca County	40,863	40,864	41,299	41,565	42,047	42,446	42,763	43,337	43,729	43,986
Jackson County	11,677	11,583	11,610	11,569	11,637	11,717	11,757	11,750	11,728	11,636
Kanabec County	12,802	12,881	13,019	13,102	13,207	13,473	13,815	14,030	14,220	14,432
Kandiyohi County	38,761	38,973	39,552	40,044	40,512	41,167	41,502	41,652	41,782	41,942
Kittson County	5,767	5,712	5,679	5,626	5,601	5,572	5,535	5,510	5,455	5,376
Koochiching County	16,299	15,808	15,807	15,811	15,822	15,911	15,947	15,868	15,826	15,679
Lac Qui Parle County	8,924	8,865	8,807	8,744	8,727	8,717	8,704	8,644	8,540	8,413
Lake County	10,415	10,370	10,353	10,363	10,398	10,473	10,558	10,695	10,700	10,745
Lake Of The Woods County	4,076	4,093	4,171	4,223	4,288	4,363	4,430	4,495	4,553	4,618
Le Sueur County	23,239	23,346	23,563	23,695	23,922	24,371	24,739	24,939	25,181	25,482
Lincoln County	6,890	6,848	6,816	6,783	6,803	6,791	6,769	6,707	6,644	6,585
Lyon County	24,789	24,774	24,776	24,979	25,195	25,211	25,284	25,431	25,484	25,505
McLeod County	32,030	32,155	32,645	32,824	33,295	33,803	34,197	34,493	34,881	35,364
Mahnomen County	5,044	5,022	5,068	5,103	5,130	5,127	5,241	5,222	5,190	5,166
Marshall County	10,993	10,916	10,870	10,819	10,766	10,733	10,716	10,676	10,465	10,383
Martin County	22,914	22,870	22,812	22,832	22,842	22,840	22,872	22,849	22,782	22,694
Meeker County	20,846	20,891	21,030	21,056	21,125	21,352	21,509	21,711	21,911	21,929
Mille Lacs County	18,670	18,786	18,993	19,164	19,298	19,807	20,212	20,648	21,026	21,355
Morrison County	29,604	29,785	30,095	30,280	30,587	30,756	31,041	31,234	31,496	31,756

Mower County	37,385	37,340	37,453	37,391	37,561	37,628	37,674	37,575	37,582	37,583
Murray County	9,660	9,602	9,597	9,613	9,568	9,606	9,637	9,624	9,573	9,544
Nicollet County	28,076	28,383	28,697	28,858	29,058	29,386	29,721	29,965	30,119	30,464
Nobles County	20,098	19,991	20,140	20,192	20,346	20,408	20,578	20,570	20,276	19,920
Norman County	7,975	7,936	7,889	7,826	7,839	7,885	7,876	7,832	7,636	7,637
Olmsted County	106,470	108,606	111,081	113,237	114,386	113,968	115,169	116,537	119,038	121,452
Otter Tail County	50,714	50,814	51,137	51,309	51,823	52,847	53,552	54,160	54,404	55,192
Pennington County	13,306	13,261	13,252	13,243	13,327	13,391	13,586	13,647	13,617	13,606
Pine County	21,264	21,403	21,755	22,006	22,509	22,816	23,323	23,582	23,937	24,496
Pipestone County	10,491	10,458	10,440	10,380	10,413	10,433	10,468	10,427	10,437	10,343
Polk County	32,498	32,467	32,692	32,673	32,835	32,904	32,885	32,808	31,765	32,004
Pope County	10,745	10,713	10,723	10,755	10,839	10,906	10,956	10,969	10,979	10,980
Ramsey County	485,765	488,363	490,258	491,306	492,909	494,674	496,068	497,423	498,090	497,919
Red Lake County	4,525	4,512	4,485	4,454	4,466	4,481	4,455	4,456	4,404	4,384
Redwood County	17,254	17,170	17,272	17,250	17,270	17,293	17,325	17,293	17,262	17,193
Renville County	17,673	17,584	17,563	17,535	17,508	17,595	17,567	17,521	17,481	17,412
Rice County	49,183	49,789	50,492	51,122	51,569	52,232	52,821	53,514	54,101	54,888
Rock County	9,806	9,771	9,750	9,739	9,813	9,870	9,943	9,966	9,855	9,801
Roseau County	15,026	15,164	15,295	15,473	15,711	16,025	16,230	16,323	16,286	16,314
St. Louis County	198,213	197,767	199,260	198,249	198,866	198,879	199,103	199,454	199,454	199,080
Scott County	57,846	59,785	61,960	64,242	66,585	69,303	71,547	75,009	77,924	81,534
Sherburne County	41,945	43,638	44,949	46,574	49,234	51,328	53,772	56,682	59,945	63,182
Sibley County	14,366	14,337	14,336	14,402	14,484	14,584	14,785	14,913	14,943	14,997
Stearns County	118,791	120,860	122,240	123,257	125,171	126,912	128,522	130,574	131,981	133,977
Steele County	30,729	30,868	31,087	31,451	31,646	31,817	32,018	32,320	32,561	32,965
Stevens County	10,634	10,607	10,592	10,527	10,597	10,575	10,637	10,694	10,609	10,535
Swift County	10,724	10,664	10,616	10,650	10,885	11,081	11,142	11,159	11,335	11,338
Todd County	23,363	23,407	23,402	23,370	23,538	23,742	23,931	24,014	23,994	24,191
Traverse County	4,463	4,428	4,383	4,345	4,343	4,374	4,374	4,331	4,250	4,212
Wabasha County	19,744	19,773	19,990	20,093	20,292	20,428	20,581	20,721	20,901	21,118
Wadena County	13,154	13,130	13,144	13,137	13,207	13,294	13,397	13,404	13,456	13,398
Waseca County	18,079	18,087	17,990	17,777	17,894	18,031	18,274	18,626	18,744	19,403
Washington County	145,896	150,664	156,276	163,500	169,300	175,441	181,741	187,475	192,979	198,606
Watonwan County	11,682	11,634	11,643	11,592	11,612	11,764	11,750	11,750	11,690	11,643
Wilkin County	7,516	7,487	7,449	7,380	7,417	7,399	7,387	7,376	7,316	7,319
Winona County	47,828	47,974	48,113	48,396	48,788	48,987	49,223	49,485	49,673	49,576
Wright County	68,710	69,742	70,984	72,673	75,087	77,232	79,984	82,493	84,926	87,779
Yellow Medicine County	11,684	11,610	11,589	11,549	11,598	11,613	11,629	11,638	11,573	11,493

HOUSEHOLD ESTIMATES	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
Minnesota	1,647,853	1,668,494	1,688,050	1,710,266	1,735,535	1,761,702	1,786,249	1,809,628	1,832,191	1,859,277
Aitkin County	5,126	5,167	5,215	5,254	5,403	5,588	5,747	5,873	5,951	6,061
Anoka County	82,437	84,458	86,427	89,108	91,862	94,340	96,313	98,570	100,685	103,423
Becker County	10,477	10,542	10,640	10,726	10,911	11,058	11,116	11,253	11,379	11,501
Beltrami County	11,870	12,085	12,286	12,367	12,644	12,863	13,051	13,312	13,534	13,817
Benton County	10,935	11,391	11,648	11,887	12,053	12,304	12,451	12,632	12,809	13,074
Big Stone County	2,463	2,440	2,408	2,391	2,370	2,376	2,350	2,355	2,351	2,330
Blue Earth County	19,277	19,439	19,598	19,767	19,978	20,085	20,188	20,329	20,466	20,589
Brown County	10,321	10,355	10,399	10,459	10,506	10,618	10,699	10,775	10,801	10,839
Carlton County	10,842	10,913	11,051	11,199	11,296	11,460	11,529	11,627	11,713	11,783
Carver County	16,601	17,161	17,660	18,445	19,352	20,155	20,937	21,723	22,444	23,524
Cass County	8,302	8,392	8,543	8,662	8,864	9,224	9,373	9,582	9,832	10,112
Chippewa County	5,245	5,229	5,235	5,231	5,243	5,237	5,271	5,305	5,272	5,380
Chisago County	10,551	10,900	11,203	11,575	12,064	12,534	12,980	13,599	14,073	14,744
Clay County	17,490	17,644	17,880	18,122	18,475	18,713	18,878	19,025	19,136	19,284
Clearwater County	3,064	3,070	3,102	3,132	3,135	3,175	3,199	3,209	3,208	3,206
Cook County	1,632	1,653	1,676	1,719	1,750	1,788	1,856	1,912	1,944	1,990
Cottonwood County	5,060	5,043	5,060	5,072	5,090	5,119	5,128	5,144	5,142	5,121
Crow Wing County	17,204	17,558	17,898	18,232	18,566	19,053	19,535	19,968	20,399	20,935
Dakota County	98,293	101,051	103,657	107,094	110,660	114,470	117,889	120,715	123,541	126,748
Dodge County	5,538	5,612	5,695	5,770	5,861	5,933	6,033	6,119	6,199	6,299
Douglas County	10,988	11,096	11,190	11,414	11,591	11,807	12,059	12,249	12,382	12,577
Faribault County	6,772	6,767	6,739	6,717	6,717	6,739	6,759	6,747	6,735	6,740
Fillmore County	7,822	7,879	7,882	7,900	7,912	7,984	8,026	8,071	8,092	8,110
Freeborn County	13,029	13,053	13,050	13,098	13,100	13,114	13,136	13,062	13,067	13,068
Goodhue County	15,198	15,398	15,606	15,759	15,917	16,113	16,276	16,435	16,597	16,754
Grant County	2,454	2,449	2,446	2,444	2,443	2,477	2,485	2,484	2,504	2,496
Hennepin County	419,060	422,649	425,720	428,556	431,508	435,216	438,871	441,474	445,149	449,330
Houston County	6,844	6,902	6,984	7,008	7,069	7,152	7,231	7,290	7,354	7,443
Hubbard County	5,781	5,859	5,974	6,066	6,148	6,378	6,515	6,637	6,731	6,907
Isanti County	8,810	9,090	9,265	9,490	9,665	9,927	10,117	10,346	10,540	10,894
Itasca County	15,461	15,586	15,741	15,875	16,078	16,261	16,409	16,655	16,826	16,940
Jackson County	4,560	4,534	4,543	4,538	4,572	4,615	4,646	4,660	4,662	4,649
Kanabec County	4,753	4,803	4,860	4,900	4,951	5,056	5,203	5,300	5,397	5,488
Kandiyohi County	14,298	14,441	14,707	14,938	15,133	15,431	15,641	15,788	15,926	16,056
Kittson County	2,274	2,259	2,245	2,232	2,232	2,233	2,230	2,231	2,221	2,210
Koochiching County	6,025	6,055	6,061	6,075	6,082	6,127	6,157	6,139	6,136	6,115
Lac Qui Parle County	3,505	3,482	3,467	3,455	3,458	3,463	3,474	3,465	3,435	3,404
Lake County	4,242	4,242	4,244	4,245	4,258	4,294	4,338	4,419	4,431	4,451
Lake Of The Woods County	1,576	1,590	1,621	1,647	1,675	1,706	1,734	1,765	1,784	1,812
Le Sueur County	8,468	8,561	8,657	8,716	8,804	8,961	9,118	9,219	9,328	9,466
Lincoln County	2,704	2,700	2,696	2,692	2,704	2,701	2,700	2,685	2,672	2,657
Lyon County	9,073	9,097	9,139	9,296	9,394	9,473	9,573	9,641	9,697	9,738
McLeod County	11,815	11,928	12,143	12,242	12,477	12,694	12,812	12,966	13,173	13,438
Mahnomen County	1,805	1,809	1,823	1,854	1,870	1,875	1,935	1,939	1,938	1,937

Marshall County	4,194	4,185	4,172	4,164	4,161	4,160	4,169	4,175	4,120	4,115
Martin County	9,129	9,139	9,129	9,156	9,178	9,199	9,240	9,265	9,267	9,276
Meeker County	7,651	7,692	7,751	7,776	7,818	7,918	8,008	8,116	8,231	8,283
Mille Lacs County	6,911	6,994	7,063	7,131	7,184	7,396	7,576	7,770	7,934	8,064
Morrison County	10,399	10,511	10,620	10,717	10,868	10,956	11,129	11,256	11,401	11,577
Mower County	15,028	15,053	15,119	15,129	15,224	15,298	15,350	15,369	15,426	15,491
Murray County	3,758	3,741	3,740	3,751	3,752	3,778	3,809	3,819	3,818	3,825
Nicollet County	9,478	9,677	9,820	9,895	10,008	10,139	10,317	10,449	10,549	10,667
Nobles County	7,683	7,707	7,809	7,846	7,924	7,966	8,059	8,091	8,013	7,894
Norman County	3,118	3,102	3,083	3,068	3,082	3,121	3,125	3,123	3,080	3,076
Olmsted County	40,058	41,141	42,189	43,120	43,696	43,584	44,145	44,891	46,111	47,247
Otter Tail County	19,510	19,636	19,790	19,910	20,162	20,633	20,994	21,307	21,479	21,843
Pennington County	5,173	5,171	5,170	5,183	5,229	5,262	5,386	5,441	5,453	5,471
Pine County	7,577	7,658	7,789	7,920	8,181	8,365	8,590	8,718	8,846	9,083
Pipestone County	4,078	4,074	4,066	4,060	4,082	4,097	4,100	4,113	4,136	4,122
Polk County	11,984	12,038	12,095	12,119	12,218	12,285	12,308	12,333	12,010	12,119
Pope County	4,135	4,130	4,136	4,161	4,207	4,247	4,287	4,316	4,351	4,368
Ramsey County	190,500	191,724	192,434	193,468	195,038	196,412	197,500	198,370	199,389	200,184
Red Lake County	1,730	1,727	1,718	1,712	1,725	1,735	1,733	1,752	1,742	1,742
Redwood County	6,554	6,535	6,593	6,600	6,622	6,647	6,691	6,706	6,729	6,735
Renville County	6,790	6,766	6,758	6,737	6,759	6,818	6,829	6,835	6,846	6,858
Rice County	16,347	16,598	16,890	17,162	17,382	17,642	17,895	18,222	18,468	18,818
Rock County	3,754	3,751	3,755	3,763	3,792	3,816	3,856	3,886	3,848	3,851
Roseau County	5,415	5,492	5,558	5,627	5,730	5,873	5,972	6,037	6,048	6,095
St. Louis County	78,901	79,016	79,333	79,592	79,876	80,184	80,527	80,979	81,156	81,435
Scott County	19,367	20,080	20,787	21,676	22,586	23,634	24,408	25,650	26,739	28,287
Sherburne County	13,643	14,236	14,667	15,240	16,143	16,859	17,700	18,727	19,755	20,853
Sibley County	5,323	5,326	5,337	5,391	5,432	5,475	5,532	5,580	5,620	5,664
Stearns County	39,776	40,626	41,259	41,787	42,452	43,190	43,925	44,861	45,538	46,439
Steele County	11,342	11,484	11,599	11,773	11,890	11,980	12,112	12,289	12,425	12,632
Stevens County	3,823	3,815	3,814	3,819	3,835	3,850	3,893	3,941	3,943	3,936
Swift County	4,268	4,257	4,245	4,234	4,261	4,275	4,291	4,338	4,329	4,310
Todd County	8,589	8,637	8,650	8,653	8,733	8,837	8,947	9,022	9,046	9,185
Traverse County	1,778	1,765	1,751	1,742	1,754	1,779	1,785	1,774	1,753	1,746
Wabasha County	7,286	7,331	7,417	7,474	7,575	7,641	7,721	7,808	7,905	8,030
Wadena County	4,978	4,983	4,989	4,997	5,038	5,091	5,152	5,173	5,212	5,210
Waseca County	6,649	6,672	6,701	6,713	6,765	6,834	6,907	6,949	7,021	7,065
Washington County	49,246	51,084	52,999	55,761	58,373	60,800	63,103	65,136	67,399	69,630
Watonwan County	4,530	4,523	4,534	4,523	4,550	4,607	4,612	4,622	4,618	4,614
Wilkin County	2,805	2,799	2,787	2,771	2,794	2,805	2,814	2,822	2,810	2,832
Winona County	16,930	17,143	17,259	17,407	17,552	17,745	17,896	18,048	18,217	18,340
Wright County	23,013	23,554	24,004	24,587	25,438	26,237	27,224	28,171	29,073	30,150
Yellow Medicine County	4,607	4,589	4,587	4,582	4,625	4,642	4,664	4,684	4,681	4,675

Title: Annual estimates of county population, households and persons per household, 2000-2009
Source: Minnesota State Demographic Center and the Metropolitan Council
Release Date: July 30, 2010

MNFIPS	County FIP	County	2009 Population	2009 Households	2009 Persons per Household	2008 Population	2008 Households	2008 Persons per Household	2007 Population	2007 Households
27001	1	Aitkin	15737	7111	2.18	16054	7235	2.19	16067	7203
27003	3	Anoka	335308	122105	2.72	332751	120891	2.72	331246	119973
27005	5	Becker	32113	13273	2.38	32302	13280	2.4	32183	13107
27007	7	Beltrami	44173	16480	2.56	43861	16397	2.56	43320	16193
27009	9	Benton	40145	15741	2.5	39805	15611	2.5	39308	15489
27011	11	Big Stone	5327	2222	2.29	5466	2261	2.31	5473	2259
27013	13	Blue Earth	61024	24175	2.35	60393	23974	2.35	59723	23699
27015	15	Brown	25929	10890	2.29	26155	10898	2.31	26344	10863
27017	17	Carlton	34266	13610	2.4	34128	13503	2.41	33990	13435
27019	19	Carver	91228	32867	2.74	89615	32283	2.74	88384	31729
27021	21	Cass	28338	12078	2.33	28654	12112	2.35	28743	11990
27023	23	Chippewa	12388	5344	2.27	12512	5365	2.28	12645	5383
27025	25	Chisago	50489	18220	2.69	50384	18057	2.71	50433	17856
27027	27	Clay	56763	22038	2.39	55900	21599	2.4	55441	21234
27029	29	Clearwater	8232	3415	2.36	8247	3412	2.37	8314	3419
27031	31	Cook	5441	2583	2.08	5437	2578	2.09	5356	2528
27033	33	Cottonwoc	11096	4757	2.26	11222	4784	2.27	11584	4869
27035	35	Crow Wing	62370	26423	2.33	61739	26053	2.33	61390	25563
27037	37	Dakota	400675	152997	2.6	398487	151450	2.61	398177	150295
27039	39	Dodge	19747	7424	2.64	19774	7415	2.64	19787	7403
27041	41	Douglas	36333	15702	2.27	36151	15540	2.29	35827	15274
27043	43	Faribault	14562	6287	2.25	14784	6344	2.26	15128	6451
27045	45	Fillmore	20828	8528	2.38	20940	8518	2.4	21086	8549
27047	47	Freeborn	31035	13374	2.28	31187	13393	2.29	31492	13444
27049	49	Goodhue	45898	18442	2.43	46018	18419	2.44	46092	18298
27051	51	Grant	5849	2473	2.3	5993	2521	2.31	6020	2517
27053	53	Hennepin	1168983	487813	2.34	1169151	485377	2.35	1157283	482265
27055	55	Houston	19381	7884	2.42	19561	7918	2.43	19779	7938
27057	57	Hubbard	18753	7987	2.33	18823	7980	2.34	18891	7924
27059	59	Isanti	39176	14725	2.63	39059	14663	2.63	38881	14416
27061	61	Itasca	44663	19212	2.29	44379	19039	2.3	44278	18774
27063	63	Jackson	10775	4587	2.29	10842	4596	2.3	11015	4627
27065	65	Kanabec	16063	6427	2.48	16311	6492	2.5	16384	6491
27067	67	Kandiyohi	41392	16819	2.42	41689	16819	2.44	41763	16826
27069	69	Kittson	4475	1949	2.24	4615	1989	2.26	4678	1999
27071	71	Koochichin	13178	5937	2.18	13302	5975	2.19	13506	6026
27073	73	Lac qui Par	7213	3162	2.23	7321	3176	2.25	7414	3186
27075	75	Lake	10853	4782	2.22	10970	4808	2.23	11119	4816
27077	77	Lake of the	3903	1851	2.08	3999	1888	2.09	4279	1892
27079	79	Le Sueur	28068	11055	2.51	28022	11034	2.51	27840	10991
27081	81	Lincoln	5806	2556	2.2	5882	2570	2.21	5943	2581
27083	83	Lyon	24964	10055	2.36	24865	9943	2.37	24940	9933
27085	85	McLeod	37058	14729	2.48	37289	14791	2.49	37130	14784
27087	87	Mahnomei	5025	1997	2.48	5085	2014	2.49	5074	2002
27089	89	Marshall	9477	4078	2.3	9648	4135	2.31	9781	4153
27091	91	Martin	20429	9013	2.22	20637	9042	2.24	20731	9004
27093	93	Meeker	23073	9218	2.46	23141	9193	2.47	23371	9185
27095	95	Mille Lacs	26378	10521	2.46	26397	10500	2.46	26171	10405
27097	97	Morrison	32722	13101	2.46	32831	13023	2.48	32947	12912
27099	99	Mower	38105	16034	2.33	38080	15978	2.34	38423	16014
27101	101	Murray	8410	3660	2.26	8526	3682	2.28	8657	3711
27103	103	Nicollet	32153	12102	2.43	32024	12023	2.44	32042	11948
27105	105	Nobles	20402	8065	2.48	20386	7988	2.5	20399	7949
27107	107	Norman	6628	2861	2.25	6789	2891	2.28	6822	2891
27109	109	Olmsted	143378	57109	2.45	141326	56383	2.45	139418	55612
27111	111	Otter Tail	56556	24010	2.3	56875	23956	2.32	58437	23953
27113	113	Penningtor	13738	5852	2.28	13694	5805	2.29	13708	5786
27115	115	Pine	28308	11014	2.41	28328	11014	2.42	28229	11073
27117	117	Pipestone	9339	4056	2.25	9364	4053	2.26	9342	4027
27119	119	Polk	30817	12527	2.34	30854	12529	2.34	31023	12500
27121	121	Pope	10922	4672	2.28	11073	4703	2.29	11110	4697
27123	123	Ramsey	517748	209214	2.38	517398	208611	2.39	517074	207678
27125	125	Red Lake	4157	1779	2.25	4111	1761	2.25	4122	1755
27127	127	Redwood	15518	6521	2.31	15680	6538	2.33	15851	6564
27129	129	Renville	15985	6760	2.31	16308	6817	2.34	16466	6827
27131	131	Rice	63408	21993	2.54	62898	21914	2.55	63034	21831
27133	133	Rock	9517	3945	2.36	9459	3923	2.36	9474	3918
27135	135	Roseau	15921	6366	2.46	16010	6376	2.47	16177	6404
27137	137	St. Louis	196036	84657	2.2	195797	84553	2.2	196108	84311
27139	139	Scott	130953	45396	2.86	128500	44645	2.85	123735	43963
27141	141	Sherburne	88122	30054	2.86	87894	29837	2.86	86308	29543
27143	143	Sibley	14988	5947	2.47	15098	5945	2.5	15288	5973
27145	145	Stearns	148671	56487	2.5	146989	55217	2.53	145877	54642
27147	147	Steele	36792	14398	2.52	36735	14374	2.51	36485	14349
27149	149	Stevens	9648	3877	2.26	9693	3873	2.27	9742	3873
27151	151	Swift	10825	4289	2.27	11312	4310	2.29	11370	4304
27153	153	Todd	23864	9784	2.41	24065	9764	2.43	24347	9728
27155	155	Traverse	3581	1576	2.2	3724	1617	2.23	3793	1635
27157	157	Wabasha	21900	8890	2.43	22205	8947	2.45	22398	8898
27159	159	Wadena	13381	5624	2.3	13532	5646	2.32	13573	5618
27161	161	Waseca	18989	7324	2.45	19456	7302	2.46	19517	7281
27163	163	Washingto	236917	88120	2.65	234348	86709	2.66	233104	85632
27165	165	Watonwan	11040	4546	2.39	11286	4588	2.42	11418	4594
27167	167	Wilkin	6419	2673	2.34	6565	2696	2.37	6709	2716
27169	169	Winona	49980	19731	2.31	50209	19541	2.34	49954	19332
27171	171	Wright	120684	44627	2.68	119335	43878	2.7	116780	42836
27173	173	Yellow Me	10040	4286	2.27	10272	4329	2.3	10428	4323

2007 Persons per Household	2006 Population	2006 Households	2006 Persons per Household	2005 Population	2005 Households	2005 Persons per Household	2004 Population	2004 Households
2.2	16198	7215	2.21	16216	7192	2.22	16085	7098
2.73	328614	119138	2.72	326393	117409	2.74	316830	114745
2.42	32256	13081	2.42	31872	12871	2.44	31813	12773
2.56	43094	16000	2.57	42698	15742	2.58	42271	15436
2.49	38774	15196	2.5	38532	15009	2.51	38018	14744
2.32	5504	2285	2.33	5495	2277	2.33	5603	2317
2.35	58977	23308	2.36	58494	22932	2.37	58118	22445
2.33	26424	10828	2.34	26555	10793	2.35	26905	10761
2.42	34220	13377	2.43	34096	13208	2.44	33748	12994
2.75	86236	30968	2.75	85204	30475	2.76	81618	29528
2.37	28949	11985	2.38	28843	11868	2.4	28453	11648
2.3	12776	5402	2.31	12781	5379	2.32	12694	5321
2.74	50278	17748	2.74	49417	17370	2.75	48424	16969
2.42	54892	20820	2.43	53946	20276	2.45	52994	19760
2.38	8453	3441	2.4	8477	3422	2.42	8456	3389
2.09	5369	2515	2.11	5368	2498	2.12	5316	2459
2.31	11750	4886	2.32	11842	4903	2.33	11935	4924
2.37	61038	25271	2.37	60194	24793	2.38	59395	24356
2.63	391613	147824	2.62	391558	146605	2.65	383076	143484
2.65	19769	7353	2.66	19596	7255	2.67	19355	7137
2.3	35477	15022	2.31	35125	14766	2.33	34590	14444
2.28	15309	6493	2.29	15486	6540	2.3	15618	6569
2.41	21241	8556	2.42	21347	8570	2.43	21359	8524
2.3	31683	13444	2.31	31904	13457	2.32	31997	13442
2.46	46086	18203	2.46	46000	18073	2.48	45679	17900
2.33	6067	2513	2.34	6098	2516	2.35	6182	2542
2.34	1152508	479483	2.34	1150912	476941	2.35	1144037	469801
2.45	19869	7925	2.46	19942	7912	2.47	19945	7876
2.36	18925	7882	2.37	18873	7831	2.38	18856	7787
2.67	38436	14158	2.68	37699	13861	2.68	36512	13347
2.33	44347	18620	2.34	44285	18479	2.36	44242	18308
2.32	11132	4636	2.33	11175	4626	2.35	11214	4621
2.51	16279	6417	2.51	16213	6349	2.53	16054	6253
2.44	41689	16729	2.45	41487	16452	2.46	41398	16344
2.28	4723	2006	2.29	4785	2033	2.29	4856	2051
2.2	13619	6004	2.22	13773	6000	2.25	13832	5998
2.27	7499	3192	2.28	7623	3227	2.3	7754	3265
2.24	11100	4787	2.25	11189	4800	2.27	11229	4791
2.23	4360	1908	2.25	4427	1920	2.27	4411	1909
2.51	27896	10947	2.52	27786	10832	2.53	27454	10617
2.23	6022	2586	2.25	6065	2585	2.26	6179	2613
2.39	24999	9895	2.4	24948	9831	2.41	25038	9837
2.48	37042	14673	2.49	36642	14443	2.5	36198	14194
2.5	5068	1997	2.5	5113	2003	2.51	5079	1975
2.33	9955	4170	2.36	9942	4136	2.37	9996	4128
2.25	20864	9007	2.26	20982	9013	2.27	21077	9009
2.49	23418	9130	2.5	23416	9082	2.52	23267	8989
2.47	26057	10308	2.48	25598	10087	2.49	25018	9813
2.51	32997	12817	2.52	32866	12649	2.54	32822	12538
2.35	38853	16060	2.36	38965	16048	2.37	38984	15996
2.3	8777	3717	2.31	8857	3721	2.33	8992	3752
2.45	31934	11846	2.45	31449	11621	2.47	31147	11448
2.51	20495	7945	2.52	20553	7930	2.53	20543	7909
2.29	6936	2901	2.31	7059	2933	2.33	7128	2944
2.45	138221	54850	2.46	136526	53847	2.47	134282	52739
2.39	58552	23843	2.4	58665	23765	2.41	58658	23642
2.3	13668	5741	2.3	13624	5692	2.31	13559	5644
2.43	28355	11031	2.45	28453	10967	2.46	28071	10738
2.27	9435	4030	2.28	9497	4027	2.3	9589	4040
2.37	31115	12484	2.38	31021	12378	2.4	31092	12287
2.3	11211	4696	2.32	11249	4682	2.33	11221	4643
2.4	515059	206149	2.4	515258	205546	2.41	515411	204123
2.27	4195	1759	2.29	4317	1793	2.31	4298	1769
2.34	16005	6558	2.36	16096	6555	2.37	16245	6587
2.36	16613	6830	2.37	16771	6858	2.39	16838	6845
2.57	62323	21483	2.57	61547	21069	2.59	60576	20612
2.36	9540	3907	2.38	9541	3883	2.39	9590	3879
2.49	16361	6421	2.51	16484	6426	2.52	16303	6318
2.21	196324	83896	2.22	198102	83545	2.25	198262	83115
2.79	119646	42512	2.78	115997	41250	2.78	112623	40021
2.85	85025	29004	2.86	82246	27978	2.86	79030	26776
2.51	15309	5932	2.52	15384	5927	2.54	15320	5873
2.54	144443	53846	2.55	142684	52827	2.56	140841	51702
2.5	36163	14163	2.51	35662	13913	2.52	35166	13657
2.29	9736	3832	2.31	9816	3791	2.33	9874	3774
2.31	11481	4301	2.32	11429	4293	2.33	11599	4276
2.47	24469	9709	2.48	24614	9706	2.5	24657	9661
2.25	3792	1635	2.25	3817	1636	2.26	3866	1646
2.48	22445	8860	2.49	22366	8782	2.5	22232	8681
2.34	13615	5591	2.35	13668	5572	2.37	13600	5513
2.48	19605	7278	2.49	19551	7226	2.5	19450	7172
2.68	228103	83762	2.67	224857	81645	2.71	217435	79321
2.45	11480	4589	2.46	11528	4591	2.47	11570	4593
2.41	6757	2721	2.42	6811	2719	2.45	6837	2710
2.36	49903	19270	2.36	49930	19167	2.38	49827	19038
2.71	114806	41923	2.71	110836	39772	2.76	106734	38040
2.33	10505	4327	2.35	10583	4334	2.36	10656	4330

2004 Persons per Household	2003 Population	2003 Households	2003 Persons per Household
2.23	15810	6966	2.24
2.73	313197	112627	2.75
2.45	31159	12481	2.45
2.6	41607	15179	2.6
2.52	36970	14311	2.52
2.34	5648	2335	2.34
2.4	57435	22039	2.41
2.36	26832	10643	2.38
2.46	33154	12768	2.46
2.72	78444	28096	2.75
2.4	28191	11482	2.41
2.33	12827	5350	2.34
2.76	46472	16270	2.76
2.46	51934	19263	2.48
2.43	8390	3366	2.43
2.13	5280	2428	2.15
2.34	11999	4929	2.35
2.39	58391	23851	2.4
2.64	375642	139966	2.66
2.68	19015	6983	2.69
2.35	34112	14137	2.36
2.31	15723	6592	2.31
2.44	21294	8446	2.46
2.33	32035	13418	2.34
2.48	45183	17648	2.49
2.35	6241	2555	2.36
2.37	1139837	467760	2.37
2.48	19965	7840	2.5
2.39	18635	7656	2.41
2.7	35321	12867	2.7
2.38	44198	18247	2.38
2.36	11168	4590	2.36
2.54	15831	6134	2.56
2.47	41288	16227	2.48
2.3	4958	2082	2.32
2.26	13986	5998	2.28
2.31	7879	3293	2.33
2.28	11160	4741	2.29
2.28	4387	1890	2.29
2.55	26664	10245	2.57
2.28	6171	2598	2.29
2.43	25000	9786	2.44
2.51	35872	14003	2.52
2.53	5108	1974	2.55
2.39	9979	4116	2.39
2.29	21228	9019	2.3
2.53	23182	8903	2.54
2.5	24254	9493	2.5
2.56	32618	12410	2.58
2.38	38909	15912	2.39
2.35	8995	3725	2.37
2.49	30881	11283	2.5
2.54	20646	7930	2.55
2.34	7223	2962	2.36
2.48	132013	51665	2.49
2.42	58785	23563	2.43
2.32	13654	5633	2.34
2.48	27734	10576	2.48
2.31	9675	4052	2.33
2.41	31025	12168	2.42
2.35	11246	4624	2.36
2.43	515274	204059	2.44
2.33	4317	1763	2.35
2.38	16317	6589	2.39
2.4	16864	6778	2.43
2.6	59749	20211	2.61
2.41	9651	3883	2.42
2.54	16323	6283	2.56
2.27	198721	82892	2.28
2.78	105196	37489	2.77
2.88	74763	25272	2.88
2.55	15366	5867	2.56
2.58	137777	50286	2.58
2.53	34691	13429	2.54
2.35	9957	3757	2.36
2.34	11698	4299	2.35
2.52	24315	9481	2.53
2.28	3912	1656	2.3
2.51	22108	8597	2.52
2.38	13619	5490	2.39
2.51	19451	7149	2.52
2.69	213395	77456	2.71
2.48	11683	4617	2.49
2.46	6951	2740	2.48
2.39	49674	18948	2.41
2.78	103010	36577	2.79
2.37	10764	4352	2.38

2002 Population	2002 Households	2002 Persons per Household	2001 Population	2001 Households	2001 Persons per Household	2000 Population	2000 Households	2000 Persons per Household
15495	6797	2.25	15434	6738	2.26	15301	6644	2.27
308171	110733	2.75	302271	108326	2.76	298084	106428	2.77
30646	12205	2.47	30329	12029	2.48	30000	11844	2.49
40959	14840	2.61	40222	14575	2.62	39650	14337	2.63
36355	13977	2.54	35286	13528	2.55	34226	13065	2.56
5683	2340	2.35	5751	2360	2.36	5820	2377	2.37
57053	21737	2.43	56271	21327	2.44	55941	21062	2.46
26740	10640	2.4	26757	10601	2.41	26911	10598	2.42
32547	12504	2.47	32146	12293	2.48	31671	12064	2.5
75312	26739	2.77	73305	25636	2.81	70205	24356	2.84
27825	11280	2.42	27650	11155	2.43	27150	10893	2.45
12994	5378	2.36	13041	5371	2.37	13088	5361	2.38
44780	15758	2.77	43090	15173	2.78	41101	14454	2.79
52024	19128	2.5	51604	18901	2.51	51229	18670	2.52
8389	3353	2.44	8416	3345	2.46	8423	3330	2.47
5223	2390	2.15	5175	2369	2.16	5168	2350	2.17
12026	4929	2.36	12048	4917	2.36	12167	4917	2.39
57132	23262	2.41	56281	22810	2.42	55099	22250	2.42
369593	137253	2.67	362348	133966	2.68	355904	131151	2.69
18575	6783	2.71	18186	6610	2.72	17731	6420	2.73
33795	13878	2.38	33368	13565	2.4	32821	13276	2.42
15975	6648	2.33	16055	6647	2.34	16181	6652	2.36
21418	8436	2.47	21282	8331	2.49	21122	8228	2.5
32206	13425	2.35	32569	13423	2.38	32584	13356	2.39
45070	17481	2.51	44664	17255	2.52	44127	16983	2.53
6266	2549	2.38	6280	2543	2.39	6289	2534	2.4
1130880	464476	2.37	1123420	459629	2.38	1116033	456129	2.38
19907	7775	2.51	19868	7723	2.52	19718	7633	2.53
18480	7564	2.42	18459	7503	2.43	18376	7435	2.44
33757	12236	2.72	32332	11636	2.73	31287	11236	2.74
44191	18103	2.4	44036	17950	2.41	43992	17789	2.43
11245	4594	2.38	11195	4554	2.39	11268	4556	2.4
15468	5978	2.56	15285	5876	2.57	14996	5759	2.58
41307	16148	2.5	41326	16080	2.51	41203	15936	2.53
5111	2120	2.34	5182	2137	2.35	5285	2167	2.37
13990	5998	2.28	14160	6025	2.3	14355	6040	2.32
7973	3312	2.34	8019	3315	2.35	8067	3316	2.36
11088	4696	2.3	11083	4678	2.3	11058	4646	2.32
4404	1888	2.3	4492	1907	2.33	4522	1903	2.35
25987	9964	2.57	25645	9762	2.59	25426	9630	2.6
6299	2629	2.31	6415	2668	2.32	6429	2653	2.34
25294	9790	2.46	25462	9771	2.47	25425	9715	2.48
35500	13789	2.53	35244	13620	2.55	34898	13449	2.55
5139	1976	2.56	5248	2000	2.58	5190	1969	2.59
9916	4072	2.4	10018	4080	2.42	10155	4101	2.44
21394	9028	2.31	21781	9120	2.33	21802	9067	2.35
22875	8764	2.55	22806	8699	2.56	22644	8590	2.57
23531	9181	2.51	22954	8910	2.51	22330	8638	2.52
32356	12226	2.6	32183	12067	2.62	31712	11816	2.63
38940	15828	2.4	38715	15665	2.41	38603	15582	2.42
9086	3734	2.38	9155	3739	2.4	9165	3722	2.41
30471	11041	2.52	30085	10867	2.54	29771	10642	2.55
20532	7879	2.55	20748	7941	2.56	20832	7939	2.57
7326	2984	2.38	7422	3013	2.39	7442	3010	2.41
129804	50563	2.5	127123	49262	2.51	124277	47807	2.53
57992	23176	2.44	57564	22934	2.45	57159	22671	2.45
13563	5591	2.34	13556	5563	2.36	13584	5525	2.37
27340	10354	2.5	26939	10160	2.51	26530	9939	2.53
9840	4091	2.34	9883	4092	2.35	9895	4069	2.37
31253	12182	2.44	31315	12124	2.45	31369	12070	2.47
11216	4577	2.38	11273	4559	2.4	11236	4513	2.42
514748	203440	2.44	512629	202011	2.45	511202	201236	2.45
4296	1747	2.36	4292	1737	2.37	4299	1727	2.39
16519	6642	2.41	16778	6686	2.43	16815	6674	2.44
17076	6819	2.44	17094	6786	2.46	17154	6779	2.47
58628	19658	2.63	57649	19268	2.63	56665	18888	2.64
9809	3908	2.45	9745	3876	2.45	9721	3843	2.46
16251	6236	2.57	16349	6237	2.58	16338	6190	2.6
199805	83159	2.29	199999	82859	2.3	200528	82619	2.31
99488	35143	2.79	94838	32902	2.85	89498	30692	2.88
71537	24040	2.9	68177	22862	2.9	64417	21581	2.9
15435	5860	2.57	15410	5820	2.59	15356	5772	2.6
136452	49376	2.61	134701	48436	2.62	133166	47604	2.64
34429	13212	2.55	34106	13044	2.56	33680	12846	2.57
10011	3764	2.38	10039	3763	2.4	10053	3751	2.42
11556	4335	2.36	11886	4354	2.38	11956	4353	2.39
24465	9472	2.55	24514	9426	2.56	24426	9342	2.58
3965	1667	2.31	4048	1692	2.33	4134	1717	2.34
21883	8465	2.54	21725	8356	2.55	21610	8277	2.56
13674	5469	2.41	13730	5461	2.43	13713	5426	2.44
19541	7119	2.53	19554	7097	2.55	19526	7059	2.56
210724	76069	2.72	206027	73604	2.75	201130	71462	2.76
11789	4636	2.5	11844	4630	2.52	11876	4627	2.52
7020	2743	2.5	7081	2745	2.52	7138	2752	2.54
49623	18778	2.43	50029	18850	2.44	49985	18744	2.46
98410	34748	2.8	94496	33139	2.82	89986	31465	2.83
10820	4381	2.39	11016	4431	2.41	11080	4439	2.42

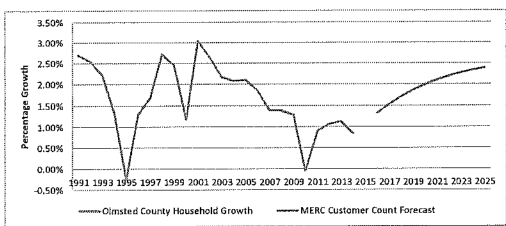
Title: 2014 estimates of county population, households and persons per household
Source: Minnesota State Demographic Center and the Metropolitan Council
Release Date: July 15, 2015

MNFIPS	County FIP	County	2014 Population	2014 Households	2014 Persons per Household	2013 Population	2013 Households	2013 Persons per Household	2012 Population
27001	1	Aitkin	15762	7164	2.16	15749	7156	2.16	15919
27003	3	Anoka	342612	125357	2.7	341465	124747	2.71	336748
27005	5	Becker	33272	13620	2.41	33167	13549	2.41	32973
27007	7	Beltrami	45770	17421	2.51	45652	17372	2.51	45325
27009	9	Benton	39518	15598	2.47	39219	15445	2.47	38861
27011	11	Big Stone	5124	2246	2.22	5127	2245	2.22	5164
27013	13	Blue Earth	65620	25499	2.41	65218	25277	2.42	65089
27015	15	Brown	25463	10786	2.26	25465	10706	2.27	25559
27017	17	Carlton	35576	13647	2.46	35505	13585	2.46	35404
27019	19	Carver	97162	34956	2.75	95463	34445	2.74	93584
27021	21	Cass	28570	12004	2.36	28604	12003	2.36	28350
27023	23	Chippewa	12132	5172	2.3	12146	5172	2.3	12181
27025	25	Chisago	54134	19719	2.66	53743	19570	2.66	53576
27027	27	Clay	61196	23363	2.47	60426	22935	2.48	60118
27029	29	Clearwater	8794	3578	2.43	8837	3591	2.43	8713
27031	31	Cook	5231	2546	2.03	5185	2519	2.04	5190
27033	33	Cottonwoc	11633	4864	2.34	11610	4862	2.34	11592
27035	35	Crow Wing	63371	26484	2.36	63216	26399	2.37	62876
27037	37	Dakota	411507	157319	2.6	408732	156459	2.59	404493
27039	39	Dodge	20352	7586	2.66	20342	7572	2.67	20237
27041	41	Douglas	36789	15757	2.3	36529	15645	2.3	36412
27043	43	Faribault	14124	6166	2.25	14192	6156	2.25	14280
27045	45	Fillmore	20783	8580	2.38	20827	8581	2.39	20837
27047	47	Freeborn	30831	13123	2.3	30917	13143	2.3	31027
27049	49	Goodhue	46480	18964	2.4	46447	18935	2.41	46331
27051	51	Grant	5923	2609	2.24	5990	2617	2.25	5950
27053	53	Hennepin	1210720	499094	2.37	1195058	491535	2.38	1180138
27055	55	Houston	18766	7944	2.33	18814	7867	2.36	18839
27057	57	Hubbard	20596	8788	2.32	20585	8772	2.33	20359
27059	59	Isanti	38397	14245	2.66	38231	14157	2.67	38235
27061	61	Itasca	45639	19088	2.33	45542	19026	2.34	45199
27063	63	Jackson	10266	4460	2.28	10265	4453	2.28	10279
27065	65	Kanabec	15966	6366	2.47	16009	6375	2.47	16011
27067	67	Kandiyohi	42258	16825	2.45	42351	16842	2.45	42315
27069	69	Kittson	4440	1949	2.22	4498	1973	2.22	4496
27071	71	Koochichin	13018	5852	2.18	13217	5865	2.21	13208
27073	73	Lac qui Par	6922	3065	2.21	7041	3096	2.22	7109
27075	75	Lake	10695	4808	2.18	10777	4821	2.19	10815
27077	77	Lake of the	3921	1762	2.19	3932	1756	2.21	3976
27079	79	Le Sueur	27791	10844	2.54	27834	10840	2.54	27673
27081	81	Lincoln	5788	2548	2.22	5830	2558	2.23	5816
27083	83	Lyon	25746	10318	2.39	25648	10243	2.4	25667
27085	85	McLeod	35942	14585	2.43	36095	14590	2.44	36104
27087	87	Mahnomei	5503	2044	2.65	5534	2055	2.65	5504
27089	89	Marshall	9420	3986	2.34	9424	3982	2.35	9445
27091	91	Martin	20295	8955	2.23	20429	8981	2.24	20477
27093	93	Meeker	23122	9185	2.48	23109	9177	2.48	23056
27095	95	Mille Lacs	25862	10160	2.5	25817	10144	2.49	25743
27097	97	Morrison	32859	13083	2.47	32877	13070	2.48	33049
27099	99	Mower	39356	15928	2.43	39356	15914	2.43	39314
27101	101	Murray	8475	3669	2.27	8536	3679	2.28	8573
27103	103	Nicollet	33350	12534	2.43	33002	12410	2.44	33018
27105	105	Nobles	21574	8016	2.64	21593	8018	2.65	21474
27107	107	Norman	6643	2791	2.33	6634	2792	2.32	6656
27109	109	Olmsted	150201	59365	2.49	149189	58866	2.49	147123
27111	111	Otter Tail	57612	24295	2.32	57588	24228	2.33	57297
27113	113	Penningtoı	14119	5964	2.31	14121	5917	2.33	14075
27115	115	Pine	29196	11328	2.42	29125	11281	2.43	29248
27117	117	Pipestone	9336	4014	2.27	9306	3988	2.28	9394
27119	119	Polk	31545	12743	2.38	31569	12739	2.37	31429
27121	121	Pope	10982	4771	2.26	10929	4741	2.27	10897
27123	123	Ramsey	529506	209659	2.44	525146	207949	2.44	517399
27125	125	Red Lake	4048	1727	2.32	4071	1737	2.32	4086
27127	127	Redwood	15573	6497	2.34	15755	6515	2.36	15842
27129	129	Renville	15067	6387	2.3	15214	6425	2.31	15389
27131	131	Rice	65180	22764	2.54	64656	22590	2.54	64747
27133	133	Rock	9555	3911	2.38	9524	3895	2.38	9567
27135	135	Roseau	15663	6346	2.44	15522	6301	2.43	15484
27137	137	St. Louis	200840	85706	2.24	200398	85451	2.24	200024
27139	139	Scott	138727	47562	2.89	136926	47111	2.88	133326
27141	141	Sherburne	91223	31077	2.86	90203	30816	2.86	89457
27143	143	Sibley	14919	5972	2.46	15074	6001	2.47	15118
27145	145	Stearns	153326	57603	2.53	152063	57057	2.53	151591
27147	147	Steele	36532	14356	2.51	36417	14382	2.49	36299
27149	149	Stevens	9836	3730	2.35	9748	3718	2.35	9751
27151	151	Swift	9453	4183	2.22	9551	4191	2.24	9609
27153	153	Todd	24266	9661	2.48	24374	9669	2.49	24526
27155	155	Traverse	3392	1493	2.2	3460	1506	2.23	3471
27157	157	Wabasha	21376	8806	2.4	21442	8806	2.41	21482
27159	159	Wadena	13768	5729	2.32	13821	5729	2.33	13778
27161	161	Waseca	19029	7303	2.43	19075	7311	2.43	19229
27163	163	Washingto	249109	91710	2.67	248095	91292	2.68	243313
27165	165	Watonwan	11095	4504	2.43	11136	4504	2.44	11188
27167	167	Wilkin	6503	2694	2.36	6558	2703	2.37	6586
27169	169	Winona	51109	19714	2.37	51362	19698	2.38	51563
27171	171	Wright	129946	46213	2.79	128459	45659	2.79	127133
27173	173	Yellow Me	10127	4216	2.33	10150	4217	2.34	10214

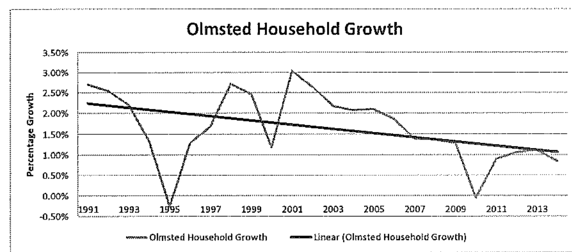
2012 Households	2012 Persons per Household	2011 Population	2011 Households	2011 Persons per Household	2010 Population	2010 Households	2010 Persons per Household
7221	2.17	16202	7330	2.17	16202	7299	2.18
122997	2.71	334053	122151	2.71	330844	121227	2.7
13477	2.41	32770	13372	2.42	32504	13224	2.42
17246	2.51	45212	17163	2.51	44442	16846	2.51
15287	2.47	38558	15155	2.48	38451	15079	2.48
2255	2.23	5240	2285	2.23	5269	2293	2.24
24935	2.43	64383	24634	2.43	64013	24445	2.43
10728	2.28	25756	10781	2.29	25893	10782	2.3
13558	2.46	35492	13586	2.46	35386	13538	2.47
33698	2.75	92104	33202	2.74	91042	32891	2.74
11919	2.36	28396	11926	2.36	28567	11948	2.37
5177	2.31	12332	5214	2.32	12441	5241	2.33
19504	2.66	53929	19537	2.67	53887	19470	2.68
22727	2.47	59644	22516	2.48	58999	22279	2.48
3540	2.43	8774	3561	2.43	8695	3527	2.43
2514	2.04	5216	2521	2.05	5176	2494	2.05
4845	2.34	11682	4860	2.35	11687	4857	2.36
26271	2.37	62745	26193	2.37	62500	26033	2.37
154274	2.6	401221	153098	2.6	398552	152060	2.6
7536	2.67	20243	7528	2.67	20087	7460	2.67
15586	2.3	36240	15498	2.3	36009	15289	2.32
6184	2.25	14506	6246	2.27	14553	6236	2.28
8584	2.39	20868	8580	2.39	20866	8545	2.4
13179	2.31	31160	13195	2.31	31255	13177	2.32
18881	2.41	46168	18803	2.41	46183	18730	2.42
2598	2.25	5993	2608	2.26	6018	2601	2.27
483488	2.39	1163060	480754	2.36	1152425	475913	2.37
7857	2.36	18933	7860	2.38	19027	7849	2.39
8696	2.32	20439	8714	2.33	20428	8661	2.34
14154	2.67	38209	14128	2.67	37816	13972	2.67
18938	2.33	45034	18847	2.34	45058	18773	2.35
4458	2.28	10203	4422	2.28	10266	4429	2.29
6382	2.47	16170	6419	2.48	16239	6413	2.49
16822	2.45	42118	16769	2.45	42239	16732	2.46
1971	2.22	4528	1984	2.23	4552	1986	2.24
5858	2.21	13221	5859	2.22	13311	5874	2.23
3117	2.23	7195	3145	2.24	7259	3155	2.25
4836	2.19	10822	4831	2.19	10866	4825	2.21
1768	2.22	4011	1777	2.23	4045	1784	2.24
10791	2.54	27655	10772	2.54	27703	10758	2.55
2553	2.23	5819	2552	2.23	5896	2574	2.24
10236	2.41	25951	10265	2.42	25857	10227	2.42
14548	2.45	36489	14628	2.46	36651	14639	2.47
2046	2.65	5441	2031	2.64	5413	2019	2.64
3991	2.35	9473	4000	2.35	9439	3981	2.35
8977	2.24	20716	9017	2.26	20840	9035	2.27
9153	2.48	23242	9181	2.49	23300	9176	2.5
10099	2.5	26003	10155	2.51	26097	10166	2.52
13103	2.48	33212	13142	2.49	33198	13080	2.5
15907	2.43	39281	15891	2.43	39163	15828	2.43
3690	2.28	8640	3701	2.29	8725	3717	2.3
12353	2.45	32949	12318	2.45	32727	12201	2.46
8001	2.64	21365	7970	2.63	21378	7946	2.64
2796	2.33	6859	2872	2.34	6852	2863	2.34
58209	2.48	145379	57595	2.48	144248	57080	2.48
24183	2.32	57243	24125	2.32	57303	24055	2.33
5898	2.33	14018	5879	2.33	13930	5836	2.33
11295	2.44	29647	11369	2.45	29750	11373	2.46
4007	2.29	9525	4038	2.31	9596	4054	2.32
12706	2.37	31489	12708	2.37	31600	12704	2.38
4728	2.27	10896	4721	2.27	10995	4736	2.28
204799	2.43	510810	203818	2.41	508640	202691	2.42
1741	2.33	4105	1747	2.33	4089	1737	2.33
6539	2.37	15986	6579	2.37	16059	6580	2.38
6483	2.32	15540	6516	2.33	15730	6564	2.34
22507	2.54	64717	22423	2.54	64142	22315	2.55
3903	2.38	9644	3915	2.4	9687	3918	2.41
6287	2.43	15536	6301	2.44	15629	6300	2.45
85098	2.24	200143	84993	2.24	200226	84783	2.25
46140	2.86	131556	45656	2.85	129928	45108	2.85
30659	2.85	88954	30439	2.85	88499	30212	2.86
6018	2.47	15193	6039	2.48	15226	6034	2.49
56755	2.53	150996	56514	2.53	150642	56232	2.53
14335	2.5	36530	14343	2.51	36576	14330	2.51
3713	2.35	9749	3724	2.36	9726	3726	2.37
4208	2.25	9677	4216	2.26	9783	4236	2.27
9693	2.5	24823	9777	2.51	24895	9756	2.52
1505	2.24	3530	1519	2.26	3558	1524	2.27
8803	2.41	21589	8827	2.42	21676	8822	2.43
5694	2.33	13709	5663	2.34	13843	5705	2.34
7338	2.44	19166	7326	2.44	19136	7281	2.44
89875	2.67	240640	88921	2.67	238136	87859	2.67
4524	2.44	11197	4525	2.44	11211	4520	2.45
2711	2.37	6584	2708	2.38	6576	2690	2.39
19721	2.39	51386	19609	2.39	51461	19554	2.4
45263	2.78	126033	44955	2.78	124700	44473	2.78
4229	2.35	10331	4260	2.36	10438	4292	2.36

	Census Total		
1970	26,639		
1980	34,345	7,706	28.93%
1990	41,603	7,258	21.13%
2000	49,422	7,819	18.79%
2010	60,495	11,073	22.41%

	Households	Household Growth	Percentage Growth
2010	57,080		-0.05%
2011	57,595	515	0.90%
2012	58,209	614	1.07%
2013	58,866	657	1.13%
2014	59,365	499	0.85%
Average			0.99%



	Households	Household Growth	Percentage Growth
2000	47,807		
2001	49,262	1,455	3.04%
2002	50,563	1,301	2.64%
2003	51,665	1,102	2.18%
2004	52,739	1,074	2.08%
2005	53,847	1,108	2.10%
2006	54,850	1,003	1.86%
2007	55,612	762	1.39%
2008	56,383	771	1.39%
2009	57,109	726	1.29%
Average			2.00%



	Households	Household Growth	Percentage Growth
1990	40,058		
1991	41,141	1,083	2.70%
1992	42,189	1,048	2.55%
1993	43,120	931	2.21%
1994	43,696	576	1.34%
1995	43,584	(112)	-0.26%
1996	44,145	561	1.29%
1997	44,891	746	1.69%
1998	46,111	1,220	2.72%
1999	47,247	1,136	2.46%
Average			1.86%
			1.66%

1991	2.70%	
1992	2.55%	
1993	2.21%	
1994	1.34%	
1995	-0.26%	
1996	1.29%	
1997	1.69%	
1998	2.72%	
1999	2.46%	
2000	1.19%	
2001	3.04%	
2002	2.64%	
2003	2.18%	
2004	2.08%	
2005	2.10%	
2006	1.86%	
2007	1.39%	
2008	1.39%	
2009	1.29%	
2010	-0.05%	
2011	0.90%	
2012	1.07%	
2013	1.13%	
2014	0.85%	
2015		
2016		1.33%
2017		1.53%
2018		1.71%
2019		1.86%
2020		1.99%
2021		2.10%
2022		2.19%
2023		2.27%
2024		2.33%
2025		2.39%

DOC Attachment 3
MERC-PNG NNG

Heating Season	Number of Firm Customers (1) No. of Design Day Customers	(2) Change from Previous Year	(3) % Change From Previous Year	Design Day Requirement (4) Design Day (Mcf)	(5) Change from Previous Year	(6) % Change From Previous Year	Total Entitlement + Peak Shaving (7) Total Entitlement (Mcf)***	(8) Change from Previous Year	(9) % Change From Previous Year	Reserve Margin (10) % of Reserve Margin [(7)-(4)]/(4)
2012-2013	158,939	1,497	0.95%	200,785	(10,397)	-4.92%	208,007	-13,429	-6.06%	3.60%
2011-2012	157,442	-856	-0.54%	211,182	16,584	8.52%	221,436	-12,191	-5.22%	4.86%
2010-2011	158,298	628	0.40%	194,598	(8,762)	-4.31%	233,627	2,563	1.11%	20.06%
2009-2010	157,670	697	0.44%	203,360	(22,037)	-9.78%	231,064	4,279	1.89%	13.62%
2008-2009	156,973	1,063	0.68%	225,397	23,134	11.44%	226,785	0	0.00%	0.62%
2007-2008	155,910	6,861	4.60%	202,263	1,779	0.89%	226,785	(741)	-0.33%	12.12%
2006-2007	149,049	741	0.50%	200,484	463	0.23%	227,526	17,399	8.28%	13.49%
2005-2006	148,308	4,412	3.07%	200,021	(7,813)	-3.76%	210,127	(9,857)	-4.48%	5.05%
2004-2005	143,896	3,191	2.27%	207,834	9,313	4.69%	219,984	13,844	6.72%	5.85%
2003-2004	140,705	3,957	2.89%	198,521	3,042	1.56%	206,140	(5,537)	-2.62%	3.84%
2002-2003	136,748	4,156	3.13%	195,479	(1,007)	-0.51%	211,677	13,282	6.69%	8.29%
2001-2002	132,592	2,844	2.19%	196,486	1,522	0.78%	198,395	0	0.00%	0.97%
2000-2001	129,748	3,446	2.73%	194,964	5,146	2.71%	198,395	7,195	3.76%	1.76%
1999-2000	126,302	3,619	2.95%	189,818	5,336	2.89%	191,200	3,425	1.82%	0.73%
1998-1999	122,683	3,102	2.59%	184,482	4,634	2.58%	187,775	6,709	3.71%	1.78%
1997-1998	119,581	700	0.59%	179,848	10,952	6.48%	181,066	27,179	17.66%	0.68%
1996-1997	118,881	2,942	2.54%	168,896	19,064	12.72%	153,887	12,792	9.07%	-8.89%
1995-1996	115,939	2,061	1.81%	149,832	(12,357)	-7.62%	141,095	0	0.00%	-5.83%
1994-1995	113,878	3,886	3.53%	162,189	5,252	3.35%	141,095	0	0.00%	-13.01%
1993-1994	109,992	2,588	2.41%	156,937	3,693	2.41%	141,095	(3,685)	-2.55%	-10.09%
1992-1993	107,404	2,705	2.58%	153,244	3,859	2.58%	144,780	0	0.00%	-5.52%
1991-1992	104,699	731	0.70%	149,385	1,043	0.70%	144,780	907	0.63%	-3.08%
1990-1991	103,968			148,342			143,873			
Average:			1.96%			1.53%			1.82%	2.57%

Firm Peak Day Sendout

Heating Season	(11) Number of Peak Day Customers	(12) Firm Peak Day Sendout (Mcf)	(13) Change from Previous Year	(14) % Change From Previous Year	(15) Excess/Def. per Cust. [(7) - (4)]/(1)	(16) Design Day per Customer** (4)/(1)	(17) Entitlement per Customer (7)/(1)	(18) Peak Day Sendout per PD Customer (12)/(11)****	(19) Peak Day Sendout per DD Customer (12)/(1)
2012-2013	unknown	unknown			0.0454	1.2633	1.3087	unknown	unknown
2011-2012	158,939	149,138	(14,004)	-8.58%	0.0651	1.3413	1.4065	0.9383	1.0095
2010-2011	157,442	163,142	11,205	7.37%	0.2466	1.2293	1.4759	1.0362	0.9946
2009-2010	158,298	151,937	(24,288)	-13.78%	0.1757	1.2898	1.4655	0.9598	1.0040
2008-2009	157,670	176,225	(6,584)	-3.60%	0.0088	1.4359	1.4447	1.1177	1.0044
2007-2008	156,973	182,809	21,626	13.42%	0.1573	1.2973	1.4546	1.1646	1.0068
2006-2007	155,910	161,183	(22,248)	-12.13%	0.1814	1.3451	1.5265	1.0338	1.0814
2005-2006	148,308	183,431	24,083	15.11%	0.0681	1.3487	1.4168	1.2368	1.2368
2004-2005	148,242	159,348	(7,019)	-4.22%	0.0844	1.4443	1.5288	1.0749	1.1074
2003-2004	143,830	166,367	7,044	4.42%	0.0541	1.4109	1.4651	1.1567	1.1824
2002-2003	140,705	159,323	17,247	12.14%	0.1185	1.4295	1.5479	1.1323	1.1651
2001-2002	137,259	142,076	(22,028)	-13.42%	0.0144	1.4819	1.4963	1.0351	1.0715
2000-2001	132,247	164,104	21,769	15.29%	0.0264	1.5026	1.5291	1.2409	1.2648
1999-2000	131,538	142,335	(13,628)	-8.74%	0.0109	1.5029	1.5138	1.0821	1.1269
1998-1999	127,014	155,963	7,292	4.90%	0.0268	1.5037	1.5306	1.2279	1.2713
1997-1998 *	122,683	148,671	(13,962)	-8.58%	0.0102	1.5040	1.5142	1.2118	1.2433
1996-1997	119,581	162,633	(13,299)	-7.56%	-0.1263	1.4207	1.2945	1.3600	1.3680
1995-1996 **	118,881	175,932	39,122	28.60%	-0.0754	1.2923	1.2170	1.4799	1.5175
1994-1995	116,296	136,810	(27,074)	-16.52%	-0.1852	1.4242	1.2390	1.1764	1.2014
1993-1994	unknown	163,884	35,896	28.05%	-0.1440	1.4268	1.2828	1.4900	1.4900
1992-1993	unknown	127,988	7,396	6.13%	-0.0788	1.4268	1.3480	1.1917	1.1917
1991-1992	unknown	120,592	(12,451)	-9.36%	-0.0440	1.4268	1.3828	1.1518	1.1518
1990-1991	unknown	133,043			-0.0430		1.3838	1.2797	1.2797
Average:				1.38%	0.0251	1.4096	1.4403	1.1717	1.1983

* The Firm Peak Day Sendout and all related amounts in columns 13, 14, and 18 for all years prior to 1997-98 have been corrected.
** The calculated historic average of "Design-Day per Customer" excludes the 1995-96 design-day per customer projection of 1.2923 Mcf/day which, as discussed in Docket No. G011/M-95-1145, was incorrectly calculated.
*** The total entitlement for 2002-2003 includes the 7,410 Mcf/day of entitlement permanently released to Cornerstone.
**** The number of design day customers are used when the number of firm peak day customers is unknown (18=19).

Prepared by the Mn Department of Commerce

DOC Attachment 2
MERC-NNG
Docket No. G011/M-15-723

	Number of Firm Customers			Design Day Requirement			Total Entitlement + Peak Shaving			Reserve Margin
Heating Season	(1) No. of Design Day Customers	(2) Change from Previous Year	(3) % Change From Previous Year	(4) Design Day (Mcf)	(5) Change from Previous Year	(6) % Change From Previous Year	(7) Total Entitlement (Mcf)*	(8) Change from Previous Year	(9) % Change From Previous Year	(10) % of Reserve Margin [(7)-(4)]/(4)
2015-2016	181,460	3,072	1.72%	245,263	(15,739)	-6.03%	252,127	-14,258	-5.35%	2.80%
2014-2015	178,388	-190	-0.11%	261,002	15,124	6.15%	266,385	10,000	3.90%	2.06%
2013-2014	178,578	1,641	0.93%	245,878	19,995	8.85%	256,385	22,900	9.81%	4.27%
2012-2013	176,937	1,696	0.97%	225,883	(9,172)	-3.90%	233,485	-12,500	-5.08%	3.37%
2011-2012	175,241	-786	-0.45%	235,055	16,842	7.72%	245,985	-15,690	-6.00%	4.65%
2010-2011	176,027	799	0.46%	218,213	(9,827)	-4.31%	261,675	7,000	2.75%	19.92%
2009-2010	175,228	1,266	0.73%	228,040	(19,148)	-7.75%	254,675	4,227	1.69%	11.68%
2008-2009	173,962	1,846	1.07%	247,188	23,434	10.47%	250,448	0	0.00%	1.32%
2007-2008	172,116	7,063	4.28%	223,754	1,635	0.74%	250,448	2036	0.82%	11.93%
2006-2007	165,053			222,119			248,412			11.84%
Average:			1.07%			1.33%			0.28%	7.38%

Columns (1) and (4) were provided by MERC in Attachment 1, page 3.

	Firm Peak Day Sendout							
Heating Season	(11) Number of Peak Day Customers	(12) Firm Peak Day Sendout (Mcf)	(13) Change from Previous Year	(14) % Change From Previous Year	(15) Excess/Def. per Cust. [(7) - (4)]/(1)	(16) Design Day per Customer (4)/(1)	(17) Entitlement per Customer (7)/(1)	(18) Peak Day Sendout per PD Customer (12)/(11)**
2015-2016	unknown	unknown			0.04	1.35	1.39	
2014-2015	178,388	193,848	(18,958)	-8.91%	0.03	1.46	1.49	1.0867
2013-2014	178,578	212,806	unknown	unknown	0.06	1.38	1.44	1.1917
2012-2013	176,937	unknown	#VALUE!	#VALUE!	0.04	1.28	1.32	#VALUE!
2011-2012	175,241	unknown	#VALUE!	#VALUE!	0.06	1.34	1.40	#VALUE!
2010-2011	176,027	unknown	#VALUE!	#VALUE!	0.25	1.24	1.49	#VALUE!
2009-2010	175,228	unknown	#VALUE!	#VALUE!	0.15	1.30	1.45	#VALUE!
2008-2009	173,962	unknown	#VALUE!	#VALUE!	0.02	1.42	1.44	#VALUE!
2007-2008	172,116	unknown	#VALUE!	#VALUE!	0.16	1.30	1.46	#VALUE!
2006-2007	165,053	unknown	#VALUE!	#VALUE!	0.16	1.35	1.51	#VALUE!
Average:				-8.91%	0.10	1.34	1.44	1.1392

Consolidation of the four into two PGAs (MERC-NNG and MERC-CON) was effective 7/1/13.
*** MERC-PNG NNG added to MERC-NMU NNG areas from DOC's prior Attachment 2 for each company.**
**** The number of design day customers are used when the number of firm peak day customers is unknown (18=19).**

Dependent Variable: UPC				
Method: Least Squares				
Date: 05/19/16 Time: 10:37				
Sample (adjusted): 2007M02 2015M02				
Included observations: 97 after adjustments				
Convergence achieved after 7 iterations				
White heteroskedasticity-consistent standard errors & covariance				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.545275	0.138950	3.924264	0.0002
AHDDMAX	0.017757	0.001666	10.65806	0.0000
FEB	-0.023852	0.044538	-0.535545	0.5937
MAR	-0.059627	0.056467	-1.055970	0.2941
APR	-0.130613	0.082330	-1.586463	0.1165
MAY	-0.170303	0.098153	-1.735079	0.0865
JUN	-0.058087	0.135473	-0.428775	0.6692
JUL	0.110454	0.142298	0.776220	0.4399
AUG	-0.009802	0.130785	-0.074948	0.9404
SEP	-0.206514	0.113334	-1.822167	0.0721
OCT	-0.084156	0.088002	-0.956293	0.3418
NOV	-0.097035	0.063718	-1.522868	0.1317
DEC	-0.057322	0.037435	-1.531247	0.1296
NGEA	-0.067670	0.041769	-1.620093	0.1091
@TREND	-0.000755	0.000652	-1.157216	0.2506
AR(1)	0.199510	0.139096	1.434336	0.1553
R-squared	0.972568	Mean dependent var		1.124352
Adjusted R-squared	0.967487	S.D. dependent var		0.535783
S.E. of regression	0.096608	Akaike info criterion		-1.686666
Sum squared resid	0.755988	Schwarz criterion		-1.261972
Log likelihood	97.80332	Hannan-Quinn criter.		-1.514941
F-statistic	191.4468	Durbin-Watson stat		1.917280
Prob(F-statistic)	0.000000			
Inverted AR Roots	.20			

Total throughput = 0.545275 + 0.017757(101 AHDD)

Total throughput = 2.336207 Dkt per customer per day

Total Rochester Area customers approximately 44,000

Total throughput = 2.336207(44000)

Total throughput = 102,793 Dkt/day

Interruptible/Transport consumption of approximately 12.5 percent

Estimate Firm throughput = 89,944 Dkt/day

Dependent Variable: COUNT				
Method: Least Squares				
Date: 05/19/16 Time: 10:28				
Sample (adjusted): 2007M02 2015M07				
Included observations: 102 after adjustments				
Convergence achieved after 4 iterations				
White heteroskedasticity-consistent standard errors & covariance				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	41367.58	56.97432	726.0741	0.0000
FEB	-16.15243	17.62851	-0.916267	0.3620
MAR	-22.44210	34.76468	-0.645543	0.5203
APR	-30.94741	40.07981	-0.772144	0.4421
MAY	-95.84946	41.48160	-2.310650	0.0232
JUN	-79.46676	44.65449	-1.779592	0.0786
JUL	-166.0576	46.33568	-3.583795	0.0006
AUG	-255.6928	65.84450	-3.883282	0.0002
SEP	-222.7735	57.45563	-3.877314	0.0002
OCT	-169.9487	46.56023	-3.650083	0.0004
NOV	-102.0900	37.78178	-2.702097	0.0083
DEC	-5.711396	21.90849	-0.260693	0.7949
@TREND	26.04455	0.815690	31.92948	0.0000
AR(1)	0.709697	0.095679	7.417477	0.0000
R-squared	0.987989	Mean dependent var		42606.56
Adjusted R-squared	0.986215	S.D. dependent var		784.3881
S.E. of regression	92.09548	Akaike info criterion		12.01040
Sum squared resid	746378.7	Schwarz criterion		12.37069
Log likelihood	-598.5305	Hannan-Quinn criter.		12.15630
F-statistic	556.8209	Durbin-Watson stat		2.136377
Prob(F-statistic)	0.000000			
Inverted AR Roots	.71			

obs	COUNTF	DOC Residential Customer	Average DOC Res	DOC SCI Customer	Average SCI Customer	DOC Interruptible	DOC LCI Customer	Average LCI Cust
2015M07	43,858							
2015M08	43,794	40,764		1,414		23	1,594	
2015M09	43,853	40,828		1,415		23	1,588	
2015M10	43,932	40,903		1,416		23	1,591	
2015M11	44,026	40,993		1,418		22	1,593	
2015M12	44,149	41,107		1,422		21	1,598	
2016M01	44,180	41,135		1,423		23	1,599	
2016M02	44,190	41,144		1,423		23	1,601	
2016M03	44,210	41,160		1,423		23	1,604	
2016M04	44,228	41,174		1,424		23	1,607	
2016M05	44,189	41,136		1,423		23	1,607	
2016M06	44,231	41,175		1,424		23	1,609	
2016M07	44,171	41,118		1,422		23	1,608	
2016M08	44,107	41,059		1,420		23	1,605	
2016M09	44,166	41,111		1,422		23	1,610	
2016M10	44,245	41,184		1,425		23	1,613	
2016M11	44,339	41,271		1,428		23	1,617	
2016M12	44,461	41,386	41,171	1,432	1,424	21	1,622	1,608
2017M01	44,493	41,413		1,433		23	1,624	
2017M02	44,503	41,421		1,434		23	1,625	
2017M03	44,523	41,438		1,435		23	1,627	
2017M04	44,540	41,454		1,436		23	1,628	
2017M05	44,501	41,417		1,435		23	1,627	
2017M06	44,544	41,456		1,437		23	1,629	
2017M07	44,483	41,398		1,435		23	1,627	
2017M08	44,420	41,339		1,433		23	1,625	
2017M09	44,479	41,393		1,436		23	1,627	
2017M10	44,557	41,466		1,439		23	1,630	
2017M11	44,651	41,554		1,442		23	1,633	
2017M12	44,774	41,668	41,451	1,446	1,437	21	1,638	1,628
2018M01	44,805	41,696		1,448		23	1,639	
2018M02	44,815	41,705		1,449		23	1,639	
2018M03	44,835	41,723		1,450		23	1,640	
2018M04	44,853	41,739		1,451		23	1,641	
2018M05	44,814	41,702		1,450		23	1,639	
2018M06	44,856	41,742		1,452		23	1,640	
2018M07	44,796	41,685		1,450		23	1,638	
2018M08	44,732	41,626		1,449		23	1,635	
2018M09	44,791	41,681		1,451		23	1,636	
2018M10	44,870	41,755		1,454		23	1,638	
2018M11	44,964	41,843		1,458		23	1,641	
2018M12	45,086	41,958	41,738	1,462	1,452	21	1,645	1,639
2019M01	45,118	41,987		1,463		23	1,645	
2019M02	45,128	41,996		1,464		23	1,645	
2019M03	45,148	42,015		1,465		23	1,644	
2019M04	45,165	42,032		1,466		23	1,644	
2019M05	45,126	41,996		1,466		23	1,642	
2019M06	45,169	42,037		1,467		23	1,642	
2019M07	45,108	41,981		1,466		23	1,639	
2019M08	45,045	41,923		1,464		22	1,635	
2019M09	45,104	41,979		1,467		22	1,636	
2019M10	45,182	42,053		1,470		22	1,637	
2019M11	45,276	42,141		1,473		23	1,639	
2019M12	45,399	42,257	42,033	1,478	1,467	21	1,643	1,641
2020M01	45,431	42,287		1,479		23	1,642	
2020M02	45,440	42,297		1,480		23	1,641	
2020M03	45,460	42,316		1,481		23	1,641	
2020M04	45,478	42,334		1,482		23	1,640	
2020M05	45,439	42,298		1,481		22	1,637	
2020M06	45,481	42,339		1,483		22	1,637	
2020M07	45,421	42,284		1,481		22	1,634	
2020M08	45,357	42,225		1,479		22	1,630	
2020M09	45,416	42,281		1,482		22	1,631	
2020M10	45,495	42,356		1,484		22	1,632	
2020M11	45,589	42,444		1,488		22	1,634	
2020M12	45,711	42,561	42,335	1,492	1,483	21	1,637	1,636

obs	COUNTF	DOC Residential Customer	Average DOC Res	DOC SCI Customer	Average SCI Customer	DOC Interruptible	DOC LCI Customer	Average LCI Cust
2021M01	45,743	42,590		1,494		22	1,637	
2021M02	45,753	42,600		1,494		22	1,636	
2021M03	45,773	42,620		1,495		22	1,635	
2021M04	45,790	42,637		1,496		22	1,635	
2021M05	45,751	42,602		1,495		22	1,632	
2021M06	45,794	42,643		1,497		22	1,632	
2021M07	45,733	42,587		1,495		22	1,628	
2021M08	45,670	42,529		1,493		22	1,625	
2021M09	45,729	42,585		1,495		22	1,626	
2021M10	45,808	42,660		1,498		22	1,627	
2021M11	45,901	42,748		1,502		22	1,629	
2021M12	46,024	42,865	42,639	1,506	1,497	21	1,632	1,631
2022M01	46,056	42,894		1,507		22	1,632	
2022M02	46,065	42,905		1,508		22	1,631	
2022M03	46,085	42,924		1,509		22	1,630	
2022M04	46,103	42,942		1,509		22	1,629	
2022M05	46,064	42,907		1,508		22	1,626	
2022M06	46,106	42,947		1,510		22	1,627	
2022M07	46,046	42,892		1,508		22	1,623	
2022M08	45,982	42,834		1,506		22	1,619	
2022M09	46,041	42,890		1,508		22	1,620	
2022M10	46,120	42,965		1,511		22	1,621	
2022M11	46,214	43,054		1,514		22	1,623	
2022M12	46,336	43,170	42,944	1,519	1,510	21	1,626	1,626
2023M01	46,368	43,200		1,520		23	1,626	
2023M02	46,378	43,211		1,520		23	1,624	
2023M03	46,398	43,231		1,521		23	1,624	
2023M04	46,415	43,248		1,522		22	1,623	
2023M05	46,376	43,213		1,521		22	1,620	
2023M06	46,419	43,254		1,522		22	1,620	
2023M07	46,358	43,199		1,520		22	1,616	
2023M08	46,295	43,142		1,518		22	1,612	
2023M09	46,354	43,198		1,521		22	1,613	
2023M10	46,433	43,273		1,523		22	1,614	
2023M11	46,526	43,362		1,526		22	1,616	
2023M12	46,649	43,479	43,251	1,531	1,522	21	1,619	1,619
2024M01	46,681	43,508		1,532		23	1,618	
2024M02	46,691	43,519		1,532		23	1,617	
2024M03	46,710	43,539		1,533		23	1,616	
2024M04	46,728	43,557		1,534		23	1,615	
2024M05	46,689	43,522		1,532		22	1,612	
2024M06	46,731	43,563		1,534		22	1,612	
2024M07	46,671	43,508		1,532		22	1,608	
2024M08	46,607	43,451		1,530		22	1,605	
2024M09	46,666	43,507		1,532		22	1,605	
2024M10	46,745	43,582		1,534		22	1,606	
2024M11	46,839	43,671		1,538		22	1,608	
2024M12	46,961	43,788	43,560	1,542	1,534	21	1,610	1,611
2025M01	46,993	43,818		1,543		23	1,610	
2025M02	47,003	43,829		1,543		23	1,608	
2025M03	47,023	43,849		1,544		23	1,608	
2025M04	47,040	43,867		1,544		23	1,607	
2025M05	47,002	43,832		1,543		23	1,604	
2025M06	47,044	43,873		1,544		23	1,604	
2025M07	46,983	43,818		1,543		22	1,600	
2025M08	46,920	43,761		1,540		22	1,596	
2025M09	46,979	43,817		1,542		22	1,597	
2025M10	47,058	43,892		1,545		22	1,598	
2025M11	47,152	43,981		1,548		23	1,600	
2025M12	47,274	44,098	43,870	1,552	1,544	21	1,602	1,603

MERC Residential Customer	MERC SCI Customer	MERC Inter Customer	MERC LCI Customer	MERC Total Customer				
MERC Residential Customer	MERC SCI Customer	MERC Inter Customer	MERC LCI Customer	MERC Total Customer				
41,018	1422.626743	22.91555537	1603.92491	44,068	0.9308	0.032283	0.00052	0.036397
41,088	1423.795267	22.93446158	1598.281652	44,133	0.931003	0.032262	0.00052	0.036215
41,155	1425.057203	22.77847498	1600.577844	44,203	0.931036	0.032239	0.000515	0.03621
41,225	1426.493739	22.62363719	1601.791784	44,276	0.931093	0.032218	0.000511	0.036178
41,273	1427.661475	21.09365428	1604.801343	44,327	0.931113	0.032208	0.000476	0.036204
41,317	1428.853627	22.97560505	1606.542469	44,376	0.93108	0.032199	0.000518	0.036203
41,356	1430.04615	22.90792503	1609.329658	44,418	0.931058	0.032195	0.000516	0.036231
41,388	1431.218156	22.91551924	1612.558521	44,455	0.931016	0.032195	0.000515	0.036274
41,420	1432.466611	23.08300834	1616.556882	44,492	0.930952	0.032196	0.000519	0.036333
41,452	1433.79361	23.0869035	1618.967225	44,528	0.930923	0.0322	0.000518	0.036358
41,505	1435.556148	23.15339414	1622.034008	44,586	0.930903	0.032198	0.000519	0.03638
41,555	1437.32229	23.13664193	1624.607209	44,640	0.93089	0.032198	0.000518	0.036394
41,610	1439.261567	23.13389351	1626.977795	44,700	0.930886	0.032198	0.000518	0.036398
41,669	1441.31171	23.22178297	1631.410556	44,765	0.930841	0.032197	0.000519	0.036444
41,730	1443.441419	23.25687586	1634.336404	44,831	0.930829	0.032197	0.000519	0.036455
41,794	1445.671101	23.15184973	1637.480898	44,900	0.930817	0.032198	0.000516	0.036469
41,847	1447.770097	21.43989129	1640.315022	44,957	0.930833	0.032203	0.000477	0.036486
41,900	1449.880024	23.18518837	1643.410096	45,016	0.93077	0.032208	0.000515	0.036507
41,949	1451.987007	23.18585074	1646.047267	45,071	0.930748	0.032216	0.000514	0.036522
41,996	1454.08003	23.15862926	1648.457603	45,122	0.930728	0.032225	0.000513	0.036533
42,044	1456.207435	23.06410367	1650.744645	45,174	0.930711	0.032236	0.000511	0.036542
42,091	1458.370576	23.05650319	1653.371295	45,226	0.930686	0.032246	0.00051	0.036558
42,149	1460.747787	23.02336999	1655.987989	45,289	0.930673	0.032254	0.000508	0.036565
42,206	1463.124301	23.03447953	1658.745441	45,351	0.930654	0.032262	0.000508	0.036576
42,266	1465.585074	23.05409685	1661.528951	45,416	0.930638	0.03227	0.000508	0.036584
42,328	1468.099534	23.01418228	1663.739912	45,483	0.930637	0.032278	0.000506	0.036579
42,391	1470.652513	23.02675494	1666.155364	45,551	0.930631	0.032286	0.000506	0.036578
42,456	1473.254583	23.11158819	1668.546421	45,621	0.930626	0.032293	0.000507	0.036574
42,516	1475.791172	21.75970105	1671.065379	45,685	0.930642	0.032304	0.000476	0.036578
42,576	1478.333193	23.08245666	1673.578755	45,751	0.930603	0.032313	0.000505	0.03658
42,635	1480.874047	23.10700534	1675.912936	45,814	0.930592	0.032323	0.000504	0.03658
42,692	1483.408536	23.13253029	1678.107369	45,877	0.930583	0.032335	0.000504	0.036579
42,750	1485.961015	23.17100003	1680.297195	45,939	0.930573	0.032346	0.000504	0.036576
42,808	1488.532404	23.19277829	1682.418699	46,003	0.930566	0.032358	0.000504	0.036572
42,872	1491.211794	23.22313044	1684.609951	46,071	0.930563	0.032367	0.000504	0.036565
42,936	1493.892367	23.24629213	1686.776568	46,140	0.93056	0.032378	0.000504	0.036558
43,001	1496.616649	23.26402172	1688.869025	46,210	0.930561	0.032387	0.000503	0.036548
43,068	1499.369576	23.29390328	1690.842371	46,281	0.930565	0.032397	0.000503	0.036534
43,135	1502.143748	23.30399963	1692.638602	46,353	0.930574	0.032407	0.000503	0.036516
43,203	1504.944575	23.29944601	1694.384525	46,426	0.930585	0.032416	0.000502	0.036497
43,270	1507.715097	21.8055177	1696.111907	46,495	0.930624	0.032427	0.000469	0.036479
43,336	1510.49077	23.36206874	1697.873896	46,567	0.930601	0.032437	0.000502	0.03646
43,402	1513.268416	23.37461706	1699.530791	46,638	0.930611	0.032447	0.000501	0.036441
43,468	1516.045541	23.38969378	1701.158758	46,708	0.93062	0.032458	0.000501	0.036421
43,534	1518.834374	23.40947665	1702.788988	46,779	0.93063	0.032468	0.0005	0.036401
43,600	1521.635454	23.42521984	1704.354894	46,850	0.930642	0.032479	0.0005	0.036379
43,670	1524.49325	23.44088906	1705.830131	46,924	0.930658	0.032489	0.0005	0.036353
43,739	1527.354601	23.45414234	1707.248153	46,997	0.930676	0.032499	0.000499	0.036326
43,810	1530.240756	23.46963925	1708.670097	47,073	0.930695	0.032508	0.000499	0.036299
43,882	1533.144263	23.48600055	1710.062559	47,148	0.930715	0.032517	0.000498	0.03627
43,954	1536.061483	23.504473	1711.465307	47,225	0.930735	0.032526	0.000498	0.036241
44,027	1538.995155	23.52030046	1712.848996	47,302	0.930757	0.032535	0.000497	0.036211
44,099	1541.916932	22.04659334	1714.205066	47,377	0.930807	0.032546	0.000465	0.036182
44,171	1544.844516	23.54776299	1715.559517	47,455	0.930799	0.032554	0.000496	0.036151
44,244	1547.776353	23.56426299	1716.864306	47,532	0.930821	0.032563	0.000496	0.03612
44,316	1550.711227	23.57986775	1718.175741	47,609	0.930843	0.032572	0.000495	0.036089
44,389	1553.655254	23.59327377	1719.527325	47,686	0.930865	0.032581	0.000495	0.036059
44,463	1556.608721	23.61180943	1720.905498	47,764	0.930886	0.03259	0.000494	0.03603
44,538	1559.593805	23.63015147	1722.319691	47,843	0.930909	0.032598	0.000494	0.035999
44,613	1562.584027	23.65163924	1723.764333	47,923	0.930931	0.032606	0.000494	0.035969
44,689	1565.589988	23.67455224	1725.255375	48,004	0.930953	0.032614	0.000493	0.03594
44,766	1568.607984	23.69520176	1726.738737	48,085	0.930975	0.032622	0.000493	0.03591
44,843	1571.636206	23.71812216	1728.223603	48,167	0.930998	0.032629	0.000492	0.03588
44,921	1574.676024	23.74466851	1729.701508	48,249	0.931022	0.032636	0.000492	0.035849
44,999	1577.713316	22.28864965	1731.168811	48,330	0.931074	0.032645	0.000461	0.03582

MERC Residential Customer	MERC SCI Customer	MERC Inter Customer	MERC LCI Customer	MERC Total Customer				
45,077	1580.756905	23.79174997	1732.67113	48,414	0.931069	0.032651	0.000491	0.035789
45,155	1583.806015	23.81640977	1734.136521	48,497	0.931093	0.032658	0.000491	0.035758
45,233	1586.860038	23.84292283	1735.651322	48,580	0.931116	0.032665	0.000491	0.035728
45,312	1589.92202	23.8726288	1737.241205	48,663	0.931138	0.032672	0.000491	0.035699
45,391	1592.992099	23.90073755	1738.815121	48,747	0.931161	0.032679	0.00049	0.03567
45,472	1596.081322	23.9287574	1740.347659	48,832	0.931185	0.032685	0.00049	0.035639
45,552	1599.176486	23.95593891	1741.863618	48,917	0.931211	0.032691	0.00049	0.035608
45,634	1602.282869	23.98429889	1743.429863	49,003	0.931235	0.032697	0.000489	0.035578
45,715	1605.398614	24.01464158	1745.023392	49,090	0.93126	0.032703	0.000489	0.035548
45,798	1608.522814	24.04504657	1746.65849	49,177	0.931284	0.032709	0.000489	0.035518
45,880	1611.656141	24.07477679	1748.310031	49,264	0.931308	0.032714	0.000489	0.035488
45,963	1614.791547	22.61860019	1749.960751	49,350	0.931361	0.032721	0.000458	0.03546
46,046	1617.933419	24.13978093	1751.641641	49,440	0.931357	0.032725	0.000488	0.03543
46,130	1621.081359	24.17046867	1753.254412	49,528	0.931382	0.03273	0.000488	0.035399
46,213	1624.235053	24.20171693	1754.883519	49,617	0.931408	0.032736	0.000488	0.035369
46,298	1627.396005	24.23422123	1756.565108	49,706	0.931433	0.032741	0.000488	0.035339
46,382	1630.564273	24.26641418	1758.216229	49,795	0.931458	0.032745	0.000487	0.035309
46,468	1633.745348	24.2977957	1759.825997	49,885	0.931486	0.03275	0.000487	0.035277
46,553	1636.932639	24.32936299	1761.433119	49,976	0.931513	0.032754	0.000487	0.035246
46,639	1640.128761	24.36297668	1763.120713	50,067	0.931539	0.032759	0.000487	0.035215
46,726	1643.332776	24.39772152	1764.861669	50,158	0.931565	0.032763	0.000486	0.035186
46,813	1646.544218	24.43341271	1766.625912	50,250	0.931591	0.032767	0.000486	0.035156
46,900	1649.763407	24.46806829	1768.330698	50,343	0.931618	0.032771	0.000486	0.035126
46,988	1652.986818	23.01504699	1769.926112	50,434	0.931674	0.032775	0.000456	0.035094
47,076	1656.216621	24.53124552	1771.492965	50,528	0.931677	0.032778	0.000485	0.03506
47,164	1659.452604	24.56204894	1773.015866	50,621	0.931708	0.032782	0.000485	0.035025
47,253	1662.694596	24.59479273	1774.623572	50,715	0.931738	0.032785	0.000485	0.034992
47,342	1665.943331	24.62970121	1776.329162	50,809	0.931766	0.032788	0.000485	0.034961
47,431	1669.198823	24.66413001	1778.002521	50,903	0.931795	0.032792	0.000485	0.034929
47,521	1672.463793	24.69685165	1779.596143	50,998	0.931826	0.032795	0.000484	0.034895
47,612	1675.734942	24.72893235	1781.153316	51,093	0.931858	0.032798	0.000484	0.034861
47,702	1679.013558	24.76252057	1782.774931	51,189	0.931889	0.0328	0.000484	0.034827
47,794	1682.299158	24.79744516	1784.455012	51,285	0.931919	0.032803	0.000484	0.034795
47,885	1685.591494	24.833531	1786.182603	51,382	0.931948	0.032805	0.000483	0.034763
47,977	1688.890711	24.86945945	1787.894277	51,479	0.931979	0.032808	0.000483	0.034731
48,069	1692.195037	23.41890003	1789.54687	51,574	0.932037	0.032811	0.000454	0.034698
48,162	1695.505537	24.93858259	1791.187114	51,673	0.932042	0.032812	0.000483	0.034664
48,255	1698.822092	24.97196287	1792.776007	51,771	0.932075	0.032814	0.000482	0.034629
48,348	1702.1446	25.00611934	1794.395151	51,869	0.932107	0.032816	0.000482	0.034595
48,441	1705.473411	25.04157154	1796.066109	51,968	0.932139	0.032818	0.000482	0.034561
48,535	1708.808519	25.07718799	1797.745282	52,067	0.932171	0.032819	0.000482	0.034528
48,630	1712.151262	25.11279368	1799.419609	52,166	0.932204	0.032821	0.000481	0.034494
48,724	1715.499982	25.14831166	1801.089069	52,266	0.932236	0.032822	0.000481	0.03446
48,819	1718.855306	25.18448309	1802.785387	52,366	0.932269	0.032824	0.000481	0.034426
48,915	1722.216977	25.22020838	1804.456436	52,467	0.932302	0.032825	0.000481	0.034392
49,011	1725.584858	25.25592814	1806.126832	52,568	0.932335	0.032826	0.00048	0.034358
49,107	1728.959005	25.29151862	1807.792272	52,669	0.932369	0.032827	0.00048	0.034324
49,203	1732.338519	23.84166774	1809.45455	52,769	0.932429	0.032829	0.000452	0.03429
49,300	1735.723917	25.36390426	1811.162015	52,872	0.932436	0.032829	0.00048	0.034255
49,397	1739.115125	25.39972554	1812.82839	52,974	0.93247	0.032829	0.000479	0.034221
49,494	1742.512076	25.43680455	1814.549632	53,077	0.932504	0.03283	0.000479	0.034187
49,592	1745.91493	25.47593101	1816.36198	53,180	0.932536	0.03283	0.000479	0.034155
49,690	1749.32367	25.51506843	1818.17179	53,283	0.932568	0.032831	0.000479	0.034123
49,789	1752.738947	25.55363318	1819.954371	53,387	0.932601	0.032831	0.000479	0.03409
49,888	1756.15992	25.59190462	1821.721446	53,491	0.932634	0.032831	0.000478	0.034057
49,987	1759.586888	25.63105801	1823.526349	53,595	0.932667	0.032831	0.000478	0.034024
50,086	1763.019707	25.67007888	1825.324546	53,700	0.9327	0.032831	0.000478	0.033991
50,186	1766.458295	25.70926528	1827.127701	53,805	0.932733	0.032831	0.000478	0.033958
50,286	1769.902665	25.74801736	1828.908866	53,911	0.932767	0.03283	0.000478	0.033925
50,386	1773.352356	24.30065488	1830.654638	54,015	0.932828	0.032831	0.00045	0.033892

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%																	
	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%		
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	2,458	308	2,174	3,506	1,094	1,595	708	552	1,666	145	3,161	337	880	104	3,561	903	1,584	489	60,433	85,658	74,129	11,529
2017/18	2,477	310	2,191	3,533	1,103	1,608	714	556	1,679	146	3,186	340	887	105	3,589	910	1,596	492	60,900	86,320	74,129	12,191
2018/19	2,496	312	2,208	3,561	1,111	1,620	719	560	1,692	148	3,210	343	894	106	3,616	917	1,608	496	61,371	86,987	74,129	12,858
2019/20	2,515	315	2,225	3,588	1,120	1,633	725	565	1,705	149	3,235	345	901	106	3,644	924	1,621	500	61,845	87,660	74,129	13,531
2020/21	2,535	317	2,242	3,616	1,129	1,645	730	569	1,718	150	3,260	348	908	107	3,672	931	1,633	504	62,323	88,338	74,129	14,209
2021/22	2,554	320	2,259	3,644	1,137	1,658	736	573	1,731	151	3,285	351	915	108	3,701	938	1,646	508	62,805	89,020	74,129	14,891
2022/23	2,574	322	2,277	3,672	1,146	1,671	742	578	1,745	152	3,311	353	922	109	3,729	946	1,659	512	63,291	89,708	74,129	15,579
2023/24	2,594	325	2,294	3,700	1,155	1,684	747	582	1,758	153	3,336	356	929	110	3,758	953	1,671	516	63,780	90,402	74,129	16,273
2024/25	2,614	327	2,312	3,729	1,164	1,697	753	587	1,772	155	3,362	359	936	111	3,787	960	1,684	520	64,273	91,101	74,129	16,972
2025/26	2,634	330	2,330	3,758	1,173	1,710	759	591	1,785	156	3,388	362	943	111	3,817	968	1,697	524	64,770	91,805	74,129	17,676
2026/27	2,654	332	2,348	3,787	1,182	1,723	765	596	1,799	157	3,414	364	951	112	3,846	975	1,710	528	65,270	92,515	74,129	18,386
2027/28	2,675	335	2,366	3,816	1,191	1,736	771	600	1,813	158	3,441	367	958	113	3,876	983	1,724	532	65,775	93,230	74,129	19,101
2028/29	2,696	337	2,384	3,846	1,200	1,750	777	605	1,827	159	3,467	370	965	114	3,906	990	1,737	536	66,283	93,950	74,129	19,821
2029/30	2,716	340	2,403	3,875	1,210	1,763	783	610	1,841	161	3,494	373	973	115	3,936	998	1,750	540	66,796	94,677	74,129	20,548
2030/31	2,737	343	2,421	3,905	1,219	1,777	789	614	1,856	162	3,521	376	980	116	3,966	1,006	1,764	544	67,312	95,408	74,129	21,279
2031/32	2,759	345	2,440	3,936	1,228	1,791	795	619	1,870	163	3,548	379	988	117	3,997	1,013	1,778	548	67,832	96,146	74,129	22,017
2032/33	2,780	348	2,459	3,966	1,238	1,805	801	624	1,884	164	3,576	382	996	118	4,028	1,021	1,791	553	68,357	96,889	74,129	22,760
2033/34	2,801	351	2,478	3,997	1,247	1,819	807	629	1,899	166	3,603	385	1,003	119	4,059	1,029	1,805	557	68,885	97,638	74,129	23,509
2034/35	2,823	353	2,497	4,028	1,257	1,833	813	634	1,914	167	3,631	388	1,011	119	4,090	1,037	1,819	561	69,418	98,393	74,129	24,264
2035/36	2,845	356	2,516	4,059	1,267	1,847	820	639	1,928	168	3,659	391	1,019	120	4,122	1,045	1,833	565	69,954	99,153	74,129	25,024
2036/37	2,867	359	2,536	4,090	1,277	1,861	826	643	1,943	169	3,688	394	1,027	121	4,154	1,053	1,847	570	70,495	99,920	74,129	25,791
2037/38	2,889	362	2,555	4,122	1,286	1,875	832	648	1,958	171	3,716	397	1,035	122	4,186	1,061	1,862	574	71,040	100,692	74,129	26,563
2038/39	2,911	364	2,575	4,154	1,296	1,890	839	653	1,973	172	3,745	400	1,043	123	4,218	1,070	1,876	579	71,589	101,471	74,129	27,342
2039/40	2,934	367	2,595	4,186	1,306	1,905	845	659	1,989	173	3,774	403	1,051	124	4,251	1,078	1,890	583	72,142	102,255	74,129	28,126
2040/41	2,957	370	2,615	4,218	1,316	1,919	852	664	2,004	175	3,803	406	1,059	125	4,284	1,086	1,905	588	72,700	103,045	74,129	28,916
2041/42	2,979	373	2,635	4,251	1,327	1,934	858	669	2,020	176	3,832	409	1,067	126	4,317	1,095	1,920	592	73,262	103,842	74,129	29,713
2042/43	3,002	376	2,656	4,283	1,337	1,949	865	674	2,035	177	3,862	412	1,075	127	4,350	1,103	1,935	597	73,828	104,645	74,129	30,516
2043/44	3,026	379	2,676	4,317	1,347	1,964	872	679	2,051	179	3,892	415	1,084	128	4,384	1,111	1,950	601	74,399	105,454	74,129	31,325
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	2,477	310	2,191	3,533	1,103	1,608	714	556	1,679	146	3,186	340	887	105	3,589	910	1,596	492	60,900	86,320
2024/25	2,614	327	2,312	3,729	1,164	1,697	753	587	1,772	155	3,362	359	936	111	3,787	960	1,684	520	64,273	91,101
2033/34	2,801	351	2,478	3,997	1,247	1,819	807	629	1,899	166	3,603	385	1,003	119	4,059	1,029	1,805	557	68,885	97,638
2042/43	3,002	376	2,656	4,283	1,337	1,949	865	674	2,035	177	3,862	412	1,075	127	4,350	1,103	1,935	597	73,828	104,645

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	1,540	(6)	839	1,507	24	680	181	45	10	146	707	65	7	49	218	32	346	72	5,731	12,191
2023/24	137	17	121	196	61	89	40	31	93	8	176	19	49	6	199	50	88	27	3,373	4,781
2032/33	188	23	166	268	84	122	54	42	127	11	241	26	67	8	272	69	121	37	4,612	6,537
2041/42	201	25	178	287	90	130	58	45	136	12	259	28	72	9	291	74	130	40	4,943	7,007

Subp.3 A **Annual Gas Consumption by Ultimate Consumers and Customers**

Calendar Sales: Units MCF **Revised with Rochester weather**

Year	Residential	%chg	Residential Customers	%chg	Small Commercial	%chg	Small Commercial Customers	%chg	Large Commercial	%chg	Large Commercial Customers	%chg
2015	3,713,977		41,010		180,305		1,414		1,675,293		1,594	
2016	3,699,106	-0.4%	41,171	0.4%	179,711	-0.3%	1,424	0.7%	1,765,690	5.4%	1,608	0.9%
2017	3,724,200	0.7%	41,451	0.7%	180,608	0.5%	1,437	0.9%	1,782,815	1.0%	1,628	1.2%
2018	3,749,857	0.7%	41,738	0.7%	181,859	0.7%	1,452	1.1%	1,799,941	1.0%	1,639	0.7%
2019	3,776,274	0.7%	42,033	0.7%	183,157	0.7%	1,467	1.1%	1,817,067	1.0%	1,641	0.1%
2020	3,803,347	0.7%	42,335	0.7%	184,385	0.7%	1,483	1.0%	1,834,193	0.9%	1,636	-0.3%
2021	3,830,611	0.7%	42,639	0.7%	185,486	0.6%	1,497	1.0%	1,851,318	0.9%	1,631	-0.3%
2022	3,857,979	0.7%	42,944	0.7%	186,454	0.5%	1,510	0.9%	1,868,444	0.9%	1,626	-0.3%
2023	3,885,530	0.7%	43,251	0.7%	187,298	0.5%	1,522	0.8%	1,885,570	0.9%	1,619	-0.4%
2024	3,913,260	0.7%	43,560	0.7%	188,029	0.4%	1,534	0.8%	1,902,696	0.9%	1,611	-0.5%
2025	3,941,101	0.7%	43,870	0.7%	188,656	0.3%	1,544	0.7%	1,919,821	0.9%	1,603	-0.5%
10 Yr Average		0.7%		0.7%		0.5%		0.9%		0.9%		0.0%

Retail Usage and Customers

Year	Residential		Residential Customers		Small Commercial		Small Commercial Customers		Large Commercial		Large Commercial Customers	
2015	3,713,977		41,010		180,305		1,414		1,675,293		1,594	
2016	3,699,106	-0.4%	41,171	0.4%	179,711	-0.3%	1,424	0.7%	1,765,690	5.4%	1,608	0.9%
2017	3,724,200	0.7%	41,451	0.7%	180,608	0.5%	1,437	0.9%	1,782,815	1.0%	1,628	1.2%
2018	3,749,857	0.7%	41,738	0.7%	181,859	0.7%	1,452	1.1%	1,799,941	1.0%	1,639	0.7%
2019	3,776,274	0.7%	42,033	0.7%	183,157	0.7%	1,467	1.1%	1,817,067	1.0%	1,641	0.1%
2020	3,803,347	0.7%	42,335	0.7%	184,385	0.7%	1,483	1.0%	1,834,193	0.9%	1,636	-0.3%
2021	3,830,611	0.7%	42,639	0.7%	185,486	0.6%	1,497	1.0%	1,851,318	0.9%	1,631	-0.3%
2022	3,857,979	0.7%	42,944	0.7%	186,454	0.5%	1,510	0.9%	1,868,444	0.9%	1,626	-0.3%
2023	3,885,530	0.7%	43,251	0.7%	187,298	0.5%	1,522	0.8%	1,885,570	0.9%	1,619	-0.4%
2024	3,913,260	0.7%	43,560	0.7%	188,029	0.4%	1,534	0.8%	1,902,696	0.9%	1,611	-0.5%
2025	3,941,101	0.7%	43,870	0.7%	188,656	0.3%	1,544	0.7%	1,919,821	0.9%	1,603	-0.5%
		0.7%		0.7%		0.5%		0.9%		0.9%		0.0%

Interruptible	%chg	Interruptible Customers	%chg	Transport	%chg	Transport Customers	%chg	Total Sales	%chg	Customers	%chg	Year	
208,100		23		4,243,211		21		10,020,886		44,062		2015	2015
198,364	-4.7%	23	0.0%	4,339,720	2.3%	22	4.8%	10,182,591	1.6%	44,249	0.4%	2016	2016
204,223	3.0%	23	0.0%	4,486,107	3.4%	23	4.5%	10,377,953	1.9%	44,562	0.7%	2017	2017
207,739	1.7%	23	0.0%	4,614,632	2.9%	24	4.3%	10,554,029	1.7%	44,876	0.7%	2018	2018
209,849	1.0%	23	0.0%	4,709,490	2.1%	25	4.2%	10,695,838	1.3%	45,190	0.7%	2019	2019
211,116	0.6%	24	4.3%	4,785,969	1.6%	25	0.0%	10,819,009	1.2%	45,503	0.7%	2020	2020
211,875	0.4%	24	0.0%	4,867,592	1.7%	26	4.0%	10,946,883	1.2%	45,817	0.7%	2021	2021
212,331	0.2%	24	0.0%	4,956,283	1.8%	27	3.8%	11,081,491	1.2%	46,130	0.7%	2022	2022
212,605	0.1%	25	4.2%	5,045,655	1.8%	27	0.0%	11,216,658	1.2%	46,444	0.7%	2023	2023
212,769	0.1%	25	0.0%	5,135,725	1.8%	28	3.7%	11,352,479	1.2%	46,757	0.7%	2024	2024
212,868	0.0%	25	0.0%	5,229,112	1.8%	29	3.6%	11,491,558	1.2%	47,071	0.7%	2025	2025
	0.2%		0.9%		2.1%		3.3%		1.4%		0.7%		

Total Retail Sales		Total Retail Customers	
5,569,575		44,018	
5,644,507	1.3%	44,204	0.4%
5,687,623	0.8%	44,516	0.7%
5,731,658	0.8%	44,829	0.7%
5,776,499	0.8%	45,142	0.7%
5,821,924	0.8%	45,454	0.7%
5,867,416	0.8%	45,767	0.7%
5,912,877	0.8%	46,079	0.7%
5,958,398	0.8%	46,392	0.7%
6,003,985	0.8%	46,704	0.7%
6,049,578	0.8%	47,017	0.7%
	0.8%		0.7%

Year	Month	Actual	Pred	DOC Yhat	Upper	Lower	Sigma
2007	1	2,035,809.000	2,371,583.958	2,409,758.585	2,745,317.177	1,997,850.739	188,354.326
2007	2	2,719,581.000	2,642,047.492	2,984,784.224	3,019,002.540	2,265,092.444	189,978.066
2007	3	2,500,345.000	2,235,272.805	2,394,219.587	2,607,914.860	1,862,630.750	187,804.401
2007	4	1,454,732.000	1,584,973.845	1,490,367.358	1,954,731.245	1,215,216.444	186,350.591
2007	5	927,973.000	667,817.512	808,587.826	1,037,450.723	298,184.302	186,288.001
2007	6	482,369.000	464,665.577	442,296.001	835,340.793	93,990.361	186,813.152
2007	7	409,082.000	236,671.881	347,921.849	607,847.595	-134,503.833	187,065.393
2007	8	385,324.000	307,378.652	354,028.953	678,593.486	-63,836.182	187,085.109
2007	9	402,309.000	346,208.990	314,644.280	717,130.873	-24,712.893	186,937.468
2007	10	467,210.000	530,592.916	305,372.623	900,890.587	160,295.245	186,622.877
2007	11	830,771.000	1,078,954.362	756,117.338	1,448,422.148	709,486.576	186,204.630
2007	12	1,960,929.000	2,062,522.024	1,918,464.712	2,434,941.267	1,690,102.782	187,692.108
2008	1	2,641,537.000	2,649,421.241	2,745,537.226	3,025,295.532	2,273,546.950	189,433.385
2008	2	2,925,777.000	2,669,109.021	2,860,146.777	3,044,782.361	2,293,435.681	189,332.110
2008	3	2,656,274.000	2,537,382.838	2,623,205.660	2,911,233.403	2,163,532.274	188,413.466
2008	4	1,711,896.000	1,726,562.534	1,706,503.621	2,096,908.035	1,356,217.034	186,646.982
2008	5	1,052,487.000	967,103.784	1,064,517.579	1,336,742.599	597,464.969	186,290.826
2008	6	606,895.000	499,909.685	562,148.712	870,628.339	129,191.031	186,835.044
2008	7	426,737.000	291,979.928	364,484.999	663,588.259	-79,628.402	187,283.424
2008	8	391,902.000	298,385.916	363,864.367	670,064.861	-73,293.029	187,319.012
2008	9	412,802.000	401,375.900	365,680.934	772,581.937	30,169.863	187,080.675
2008	10	515,988.000	601,944.875	401,391.800	972,390.573	231,499.178	186,697.479
2008	11	873,228.000	1,139,901.204	831,020.266	1,509,607.489	770,194.920	186,324.829
2008	12	1,920,295.000	2,088,717.321	1,955,603.927	2,461,232.793	1,716,201.848	187,740.606
2009	1	3,032,694.000	2,709,066.545	2,839,886.746	3,085,409.288	2,332,723.801	189,669.476
2009	2	2,845,024.000	2,776,288.278	2,816,487.692	3,151,411.116	2,401,165.440	189,054.668
2009	3	2,161,162.000	2,187,678.999	2,352,080.369	2,559,903.679	1,815,454.318	187,594.052
2009	4	1,613,953.000	1,564,739.688	1,609,251.822	1,934,950.193	1,194,529.183	186,578.947
2009	5	925,092.000	901,234.172	967,986.024	1,271,293.560	531,174.783	186,502.787
2009	6	544,298.000	521,921.021	615,166.038	892,920.297	150,921.744	186,976.472
2009	7	435,109.000	325,006.704	439,715.310	696,812.292	-46,798.884	187,382.838
2009	8	419,794.000	345,613.720	425,590.100	717,549.115	-26,321.674	187,448.258
2009	9	401,078.000	391,517.826	366,005.851	763,223.733	19,811.919	187,332.600
2009	10	538,065.000	822,767.612	631,507.347	1,193,081.781	452,453.443	186,631.191
2009	11	1,033,625.000	1,137,020.943	922,783.454	1,506,982.792	767,059.094	186,453.629
2009	12	1,484,561.000	1,786,214.268	1,568,257.417	2,157,145.496	1,415,283.041	186,942.177
2010	1	2,726,599.000	2,733,082.467	2,928,638.005	3,109,865.736	2,356,299.198	189,891.493
2010	2	2,621,850.000	2,521,054.238	2,709,594.442	2,895,287.617	2,146,820.860	188,606.397
2010	3	2,207,909.000	2,241,834.979	2,394,326.771	2,614,208.306	1,869,461.651	187,668.967
2010	4	1,211,604.000	1,198,364.648	1,236,162.872	1,568,428.431	828,300.865	186,505.001
2010	5	744,596.000	808,196.242	890,311.771	1,178,769.449	437,623.035	186,761.741
2010	6	517,274.000	379,510.207	510,728.166	751,388.128	7,632.285	187,419.292
2010	7	417,107.000	334,457.686	396,694.623	707,004.472	-38,089.101	187,756.387
2010	8	357,126.000	296,888.692	389,624.532	669,544.487	-75,767.102	187,811.325
2010	9	373,951.000	405,757.845	388,674.707	777,897.796	33,617.893	187,551.350
2010	10	482,761.000	637,091.154	460,790.642	1,008,242.692	265,939.616	187,053.209
2010	11	712,486.000	1,079,440.354	803,580.577	1,449,695.938	709,184.770	186,601.666
2010	12	1,866,744.000	2,079,871.372	1,996,407.374	2,452,468.015	1,707,274.729	187,781.514
2011	1	2,812,056.000	2,361,887.260	2,505,524.824	2,735,615.695	1,988,158.826	188,351.915
2011	2	2,720,536.000	2,812,859.700	2,797,641.826	3,187,506.519	2,438,212.881	188,814.763
2011	3	2,251,950.000	2,139,447.498	2,380,786.988	2,511,736.625	1,767,158.372	187,626.532
2011	4	1,622,837.000	1,694,813.445	1,681,025.768	2,065,443.721	1,324,183.170	186,790.503

Year	Month	Actual	Pred	DOC Yhat	Upper	Lower	Sigma
2011	5	1,087,497.000	1,023,049.770	1,153,411.227	1,393,557.704	652,541.835	186,728.845
2011	6	606,896.000	503,080.435	579,509.018	875,208.644	130,952.226	187,545.432
2011	7	444,129.000	361,186.631	441,641.941	734,095.489	-11,722.227	187,938.865
2011	8	605,855.000	308,706.654	403,110.274	681,884.617	-64,471.309	188,074.488
2011	9	409,292.000	528,779.481	405,761.670	901,398.927	156,160.035	187,793.006
2011	10	516,548.000	610,607.752	476,060.625	982,185.524	239,029.979	187,268.023
2011	11	794,451.000	1,156,019.328	855,713.967	1,526,557.933	785,480.724	186,744.302
2011	12	1,765,738.000	1,713,171.508	1,616,967.181	2,084,417.461	1,341,925.556	187,100.792
2012	1	2,132,358.000	2,427,796.142	2,450,178.140	2,801,152.747	2,054,439.536	188,164.520
2012	2	2,479,336.000	2,047,655.464	2,359,698.162	2,419,961.336	1,675,349.591	187,634.971
2012	3	2,044,808.000	1,920,820.964	1,910,596.028	2,291,752.711	1,549,889.217	186,942.438
2012	4	1,003,941.000	1,024,895.665	985,873.088	1,395,891.271	653,900.059	186,974.622
2012	5	871,433.000	787,972.866	888,342.535	1,159,416.190	416,529.543	187,200.263
2012	6	508,859.000	434,741.773	501,491.012	807,775.288	61,708.258	188,001.689
2012	7	422,705.000	322,952.294	417,560.402	696,589.005	-50,684.416	188,305.688
2012	8	381,293.000	341,624.027	430,591.671	715,274.308	-32,026.254	188,312.527
2012	9	399,869.000	390,979.076	385,919.751	764,278.547	17,679.606	188,135.725
2012	10	561,505.000	759,101.957	570,410.146	1,130,870.724	387,333.190	187,364.280
2012	11	1,055,057.000	1,134,020.071	883,048.040	1,504,874.227	763,165.914	186,903.334
2012	12	1,557,510.000	1,734,116.080	1,507,291.169	2,105,265.742	1,362,966.417	187,052.264
2013	1	2,656,205.000	2,712,905.859	2,853,365.089	3,088,553.376	2,337,258.342	189,319.096
2013	2	2,789,395.000	2,458,137.511	2,672,527.205	2,831,881.928	2,084,393.093	188,359.970
2013	3	2,552,175.000	2,440,318.698	2,495,153.555	2,813,116.464	2,067,520.932	187,882.876
2013	4	2,095,178.000	2,097,886.060	2,100,022.883	2,469,777.149	1,725,994.971	187,425.928
2013	5	1,537,184.000	1,175,845.895	1,281,364.220	1,546,930.275	804,761.516	187,019.363
2013	6	668,318.000	738,738.729	686,083.854	1,111,532.181	365,945.276	187,880.702
2013	7	461,390.000	282,982.548	445,614.719	657,106.267	-91,141.172	188,551.131
2013	8	458,715.000	416,139.528	471,954.136	790,205.955	42,073.102	188,522.257
2013	9	413,715.000	388,960.788	383,887.505	762,891.430	15,030.145	188,453.824
2013	10	466,023.000	664,434.797	466,708.887	1,037,086.485	291,783.108	187,809.256
2013	11	1,134,349.000	1,351,047.076	1,108,776.646	1,722,128.892	979,965.260	187,018.071
2013	12	1,988,828.000	2,225,250.408	2,080,111.990	2,598,225.253	1,852,275.564	187,972.120
2014	1	3,453,758.000	2,827,211.538	2,879,811.910	3,210,413.968	2,444,009.108	193,126.626
2014	2	3,453,287.000	3,478,151.767	3,284,483.433	3,863,107.078	3,093,196.456	194,010.044
2014	3	3,177,539.000	2,932,189.285	3,050,275.970	3,315,382.310	2,548,996.259	193,121.886
2014	4	2,056,101.000	2,190,770.024	2,013,587.799	2,570,292.092	1,811,247.956	191,271.795
2014	5	1,261,949.000	1,279,195.181	1,330,384.148	1,658,511.566	899,878.796	191,168.134
2014	6	704,013.000	667,311.295	670,576.452	1,048,768.129	285,854.460	192,246.880
2014	7	490,174.000	561,671.082	563,254.275	943,824.749	179,517.414	192,598.070
2014	8	494,695.000	500,855.248	557,133.596	883,101.073	118,609.423	192,644.515
2014	9	454,032.000	641,002.096	547,229.827	1,022,689.912	259,314.280	192,363.290
2014	10	603,187.000	956,931.805	748,318.576	1,337,009.953	576,853.656	191,552.048
2014	11	1,049,855.000	1,500,242.008	1,216,054.506	1,879,317.424	1,121,166.591	191,046.691
2014	12	2,378,670.000	2,356,077.273	2,205,232.264	2,737,008.099	1,975,146.448	191,981.781
2015	1	2,792,696.000	2,741,345.919	2,671,011.475	3,123,045.875	2,359,645.962	192,369.408
2015	2	2,720,314.000	2,735,456.005	2,789,736.240	3,117,036.622	2,353,875.388	192,309.263
2015	3	2,932,033.000	2,773,644.024	2,883,550.072	3,155,548.459	2,391,739.590	192,472.461
2015	4	1,756,959.000	1,850,138.029	1,704,405.788	2,229,227.146	1,471,048.912	191,053.596
2015	5	1,104,315.000	1,100,175.767	1,127,620.669	1,480,066.318	720,285.217	191,457.503
2015	6	688,779.000	762,055.273	759,701.746	1,143,406.217	380,704.330	192,193.513
2015	7	486,799.000	522,919.022	576,343.883	905,360.117	140,477.927	192,742.928
2015	8		534,074.287	569,911.371	916,578.931	151,569.643	192,774.955

Year	Month	Actual	Pred	DOC Yhat	Upper	Lower	Sigma
2015	9		635,607.630	547,028.475	1,017,667.836	253,547.423	192,550.967
2015	10		998,119.604	597,797.354	1,378,566.797	617,672.412	191,738.040
2015	11		1,557,889.543	893,682.206	1,937,066.179	1,178,712.907	191,097.704
2015	12		2,311,309.749	1,632,142.965	2,691,167.747	1,931,451.750	191,441.097
2016	1		2,872,012.021	2,817,849.608	3,254,148.790	2,489,875.252	192,589.553
2016	2		2,821,355.037	2,903,894.930	3,203,197.908	2,439,512.166	192,441.435
2016	3		2,478,691.638	2,573,551.239	2,859,029.787	2,098,353.490	191,683.083
2016	4		1,876,769.182	1,807,674.878	2,255,893.826	1,497,644.538	191,071.500
2016	5		1,222,196.879	1,211,178.804	1,602,056.085	842,337.674	191,441.705
2016	6		787,871.609	789,706.453	1,169,402.943	406,340.275	192,284.426
2016	7		578,793.310	600,996.684	961,479.579	196,107.041	192,866.491
2016	8		562,968.545	590,489.064	945,781.513	180,155.576	192,930.345
2016	9		648,062.365	554,476.443	1,030,413.385	265,711.345	192,697.532
2016	10		1,010,574.340	718,718.155	1,391,229.798	629,918.882	191,843.001
2016	11		1,570,344.278	1,125,118.746	1,949,598.812	1,191,089.745	191,136.962
2016	12		2,323,764.484	1,963,241.657	2,703,523.299	1,944,005.669	191,391.111
2017	1		2,884,466.756	2,832,121.072	3,266,374.558	2,502,558.954	192,474.158
2017	2		2,833,809.772	2,918,166.393	3,215,437.733	2,452,181.812	192,333.124
2017	3		2,491,146.374	2,587,822.702	2,871,352.441	2,110,940.307	191,616.517
2017	4		1,889,223.917	1,821,946.341	2,268,361.768	1,510,086.066	191,078.157
2017	5		1,234,651.615	1,225,450.267	1,614,681.893	854,621.337	191,527.923
2017	6		800,326.344	803,977.916	1,182,133.024	418,519.664	192,423.195
2017	7		591,248.045	615,268.147	974,260.382	208,235.708	193,030.823
2017	8		575,423.280	604,760.527	958,568.172	192,278.388	193,097.628
2017	9		660,517.100	568,747.906	1,043,182.590	277,851.610	192,856.019
2017	10		1,023,029.075	732,989.618	1,403,916.673	642,141.477	191,959.995
2017	11		1,582,799.014	1,139,390.209	1,962,155.514	1,203,442.514	191,188.351
2017	12		2,336,219.219	1,977,513.120	2,715,902.890	1,956,535.549	191,353.239
2018	1		2,896,921.492	2,846,392.535	3,278,624.125	2,515,218.858	192,370.758
2018	2		2,846,264.508	2,932,437.857	3,227,701.390	2,464,827.626	192,236.824
2018	3		2,503,601.109	2,602,094.166	2,883,699.086	2,123,503.131	191,562.042
2018	4		1,901,678.653	1,836,217.804	2,280,853.807	1,522,503.498	191,096.957
2018	5		1,247,106.350	1,239,721.730	1,627,331.654	866,881.047	191,626.212
2018	6		812,781.079	818,249.379	1,194,886.819	430,675.340	192,573.915
2018	7		603,702.780	629,539.610	987,064.741	220,340.819	193,207.026
2018	8		587,878.015	619,031.990	971,378.368	204,377.663	193,276.773
2018	9		672,971.836	583,019.369	1,055,975.393	289,968.279	193,026.398
2018	10		1,035,483.811	747,261.082	1,416,627.379	654,340.242	192,089.000
2018	11		1,595,253.749	1,153,661.673	1,974,736.265	1,215,771.233	191,251.861
2018	12		2,348,673.955	1,991,784.583	2,728,306.533	1,969,041.377	191,327.489
2019	1		2,909,376.227	2,860,663.998	3,290,897.531	2,527,854.923	192,279.371
2019	2		2,858,719.243	2,946,709.320	3,239,988.915	2,477,449.571	192,152.553
2019	3		2,516,055.844	2,616,365.629	2,896,069.745	2,136,041.944	191,519.669
2019	4		1,914,133.388	1,850,489.268	2,293,369.935	1,534,896.841	191,127.897
2019	5		1,259,561.086	1,253,993.194	1,640,005.330	879,116.841	191,736.554
2019	6		825,235.815	832,520.843	1,207,664.272	442,807.358	192,736.558
2019	7		616,157.516	643,811.074	999,892.592	232,422.439	193,395.069
2019	8		600,332.751	633,303.454	984,212.036	216,453.465	193,467.748
2019	9		685,426.571	597,290.833	1,068,791.730	302,061.412	193,208.638
2019	10		1,047,938.546	761,532.545	1,429,361.868	666,515.224	192,229.990
2019	11		1,607,708.485	1,167,933.136	1,987,341.042	1,228,075.927	191,327.479
2019	12		2,361,128.690	2,006,056.047	2,740,734.238	1,981,523.143	191,313.867

Year	Month	Actual	Pred	DOC Yhat	Upper	Lower	Sigma
2020	1		2,921,830.962	2,874,935.462	3,303,194.808	2,540,467.117	192,200.015
2020	2		2,871,173.979	2,960,980.783	3,252,300.340	2,490,047.617	192,080.328
2020	3		2,528,510.580	2,630,637.092	2,908,464.432	2,148,556.728	191,489.405
2020	4		1,926,588.123	1,864,760.731	2,305,910.140	1,547,266.107	191,170.972
2020	5		1,272,015.821	1,268,264.657	1,652,702.882	891,328.760	191,858.929
2020	6		837,690.550	846,792.306	1,220,465.322	454,915.778	192,911.095
2020	7		628,612.251	658,082.537	1,012,743.866	244,480.636	193,594.917
2020	8		612,787.486	647,574.917	997,069.107	228,505.865	193,670.517
2020	9		697,881.307	611,562.296	1,081,631.536	314,131.077	193,402.706
2020	10		1,060,393.281	775,804.008	1,442,120.087	678,666.476	192,382.939
2020	11		1,620,163.220	1,182,204.599	1,999,969.816	1,240,356.624	191,415.191
2020	12		2,373,583.426	2,020,327.510	2,753,186.010	1,993,980.841	191,312.373
2021	1		2,934,285.698	2,889,206.925	3,315,515.987	2,553,055.409	192,132.705
2021	2		2,883,628.714	2,975,252.247	3,299,713.614	2,467,543.814	209,698.756
2021	3		2,540,965.315	2,644,908.556	2,956,053.131	2,125,877.499	209,196.245
2021	4		1,939,042.859	1,879,032.195	2,353,685.627	1,524,400.090	208,971.949
2021	5		1,284,470.556	1,282,536.120	1,700,506.677	868,434.436	209,674.172
2021	6		850,145.286	861,063.769	1,268,188.498	432,102.073	210,685.707
2021	7		641,066.987	672,354.000	1,060,400.012	221,733.961	211,335.749
2021	8		625,242.221	661,846.380	1,044,718.112	205,766.331	211,407.750
2021	9		710,336.042	625,833.760	1,129,308.872	291,363.212	211,154.217
2021	10		1,072,848.017	790,075.472	1,489,891.848	655,804.186	210,182.039
2021	11		1,632,617.955	1,196,476.063	2,047,785.178	1,217,450.733	209,236.264
2021	12		2,386,038.161	2,034,598.973	2,800,856.763	1,971,219.559	209,060.566
2022	1		2,946,740.433	2,903,478.388	3,362,929.433	2,530,551.433	209,751.220
2022	2		2,896,083.449	2,989,523.710	3,312,080.963	2,480,085.936	209,654.715
2022	3		2,553,420.050	2,659,180.019	2,968,496.918	2,138,343.183	209,190.727
2022	4		1,951,497.594	1,893,303.658	2,366,262.594	1,536,732.594	209,033.552
2022	5		1,296,925.292	1,296,807.584	1,713,227.363	880,623.220	209,808.206
2022	6		862,600.021	875,335.233	1,281,003.743	444,196.299	210,867.397
2022	7		653,521.722	686,625.464	1,073,261.191	233,782.253	211,540.588
2022	8		637,696.957	676,117.844	1,057,584.593	217,809.320	211,615.262
2022	9		722,790.777	640,105.223	1,142,159.555	303,421.999	211,353.767
2022	10		1,085,302.752	804,346.935	1,502,667.948	667,937.556	210,344.000
2022	11		1,645,072.691	1,210,747.526	2,060,443.056	1,229,702.325	209,338.644
2022	12		2,398,492.896	2,048,870.437	2,813,352.836	1,983,632.957	209,081.400
2023	1		2,959,195.168	2,917,749.852	3,375,305.707	2,543,084.630	209,711.677
2023	2		2,908,538.185	3,003,795.173	3,324,470.260	2,492,606.110	209,621.735
2023	3		2,565,874.786	2,673,451.482	2,980,962.716	2,150,786.855	209,196.303
2023	4		1,963,952.330	1,907,575.121	2,378,861.546	1,549,043.113	209,106.234
2023	5		1,309,380.027	1,311,079.047	1,725,969.812	892,790.243	209,953.208
2023	6		875,054.756	889,606.696	1,293,840.495	456,269.018	211,059.926
2023	7		665,976.457	700,896.927	1,086,143.721	245,809.194	211,756.188
2023	8		650,151.692	690,389.307	1,070,472.409	229,830.976	211,833.526
2023	9		735,245.513	654,376.686	1,155,031.630	315,459.395	211,564.098
2023	10		1,097,757.488	818,618.398	1,515,465.674	680,049.301	210,516.861
2023	11		1,657,527.426	1,225,018.989	2,073,122.820	1,241,932.032	209,452.054
2023	12		2,410,947.632	2,063,141.900	2,825,870.925	1,996,024.339	209,113.328
2024	1		2,971,649.904	2,932,021.315	3,387,703.927	2,555,595.881	209,683.194
2024	2		2,920,992.920	3,018,066.637	3,336,881.515	2,505,104.325	209,599.822
2024	3		2,578,329.521	2,687,722.946	2,993,450.524	2,163,208.518	209,212.970
2024	4		1,976,407.065	1,921,846.585	2,391,482.460	1,561,331.670	209,189.985

Year	Month	Actual	Pred	DOC Yhat	Upper	Lower	Sigma
2024	5		1,321,834.763	1,325,350.510	1,738,733.978	904,935.547	210,109.155
2024	6		887,509.492	903,878.159	1,306,698.695	468,320.288	211,263.265
2024	7		678,431.193	715,168.390	1,099,047.538	257,814.847	211,982.517
2024	8		662,606.428	704,660.770	1,083,381.492	241,831.363	212,062.508
2024	9		747,700.248	668,648.150	1,167,925.033	327,475.463	211,785.178
2024	10		1,110,212.223	832,889.862	1,528,284.973	692,139.473	210,700.594
2024	11		1,669,982.161	1,239,290.453	2,085,824.433	1,254,139.890	209,576.476
2024	12		2,423,402.367	2,077,413.363	2,838,411.020	2,008,393.714	209,156.348
2025	1		2,984,104.639	2,946,292.778	3,400,124.101	2,568,085.178	209,665.776
2025	2		2,933,447.656	3,032,338.100	3,349,314.737	2,517,580.574	209,588.980
2025	3		2,590,784.257	2,701,994.409	3,005,960.336	2,175,608.177	209,240.728
2025	4		1,988,861.800	1,936,118.048	2,404,125.309	1,573,598.291	209,284.791
2025	5		1,334,289.498	1,339,621.974	1,751,519.813	917,059.183	210,276.023
2025	6		899,964.227	918,149.623	1,319,578.281	480,350.173	211,477.382
2025	7		690,885.928	729,439.854	1,111,972.575	269,799.281	212,219.540
2025	8		675,061.163	718,932.234	1,096,311.775	253,810.551	212,302.175
2025	9		760,154.984	682,919.613	1,180,839.698	339,470.269	212,016.973
2025	10		1,122,666.958	847,161.325	1,541,125.789	704,208.128	210,895.171
2025	11		1,682,436.897	1,253,561.916	2,098,547.858	1,266,325.936	209,711.890
2025	12		2,435,857.102	2,091,684.827	2,850,973.107	2,020,741.098	209,210.451

Year	Month	Actual	Pred	Upper	Lower	Sigma	DOC Customer	MERC Customer	DOC Sales	MERC Sales	DOC Annual	MERC Annual
2007	1	119.472	166.902	204.395	129.410	18.896						
2007	2	184.178	168.899	206.792	131.005	19.098						
2007	3	170.407	163.165	200.521	125.808	18.827						
2007	4	67.449	98.600	135.598	61.603	18.646						
2007	5	36.413	13.514	50.497	-23.469	18.639						
2007	6	11.462	19.144	56.257	-17.969	18.704						
2007	7	9.195	-10.960	26.217	-48.136	18.736						
2007	8	8.547	7.651	44.832	-29.530	18.739						
2007	9	8.525	1.166	38.310	-35.979	18.720						
2007	10	9.823	20.992	58.059	-16.074	18.681						
2007	11	28.050	56.811	93.774	19.849	18.628						
2007	12	111.091	130.579	167.909	93.249	18.814						
2008	1	171.425	178.449	216.209	140.689	19.030						
2008	2	200.345	184.865	222.601	147.130	19.018						
2008	3	176.478	179.631	217.140	142.123	18.903						
2008	4	92.752	106.948	144.020	69.876	18.683						
2008	5	50.922	43.333	80.317	6.349	18.639						
2008	6	16.706	16.699	53.818	-20.421	18.708						
2008	7	10.178	-5.989	31.242	-43.221	18.764						
2008	8	8.913	4.253	41.493	-32.987	18.768						
2008	9	10.659	6.181	43.362	-31.001	18.739						
2008	10	12.382	25.043	62.129	-12.043	18.691						
2008	11	34.351	60.152	97.145	23.159	18.644						
2008	12	116.961	133.973	171.315	96.630	18.820						
2009	1	226.757	185.969	223.788	148.150	19.060						
2009	2	228.113	212.107	249.774	174.439	18.984						
2009	3	167.622	157.407	194.714	120.100	18.802						
2009	4	97.460	106.879	143.935	69.823	18.676						
2009	5	42.367	37.548	74.586	0.510	18.667						
2009	6	18.811	17.479	54.635	-19.677	18.726						
2009	7	12.566	-0.730	36.527	-37.987	18.777						
2009	8	15.028	5.642	42.915	-31.631	18.785						
2009	9	12.242	7.898	45.142	-29.347	18.771						
2009	10	18.957	41.373	78.443	4.302	18.683						
2009	11	51.594	59.255	96.281	22.229	18.660						
2009	12	84.037	114.540	151.686	77.393	18.721						
2010	1	201.562	182.327	220.202	144.451	19.088						
2010	2	180.482	187.825	225.384	150.267	18.929						
2010	3	141.382	143.522	180.849	106.196	18.812						
2010	4	68.890	68.067	105.106	31.028	18.667						
2010	5	32.690	36.902	74.006	-0.202	18.700						
2010	6	21.014	1.801	39.068	-35.466	18.782						
2010	7	14.378	6.452	43.803	-30.899	18.824						
2010	8	12.705	-2.247	35.117	-39.612	18.831						
2010	9	16.139	11.916	49.217	-25.384	18.799						
2010	10	17.868	26.525	63.702	-10.652	18.736						
2010	11	34.103	57.741	94.805	20.676	18.680						
2010	12	131.118	135.633	172.988	98.277	18.826						
2011	1	221.694	165.384	202.880	127.887	18.897						
2011	2	216.422	218.101	255.712	180.490	18.955						
2011	3	171.851	144.791	182.108	107.474	18.807						
2011	4	113.955	120.812	157.923	83.701	18.703						
2011	5	44.990	50.728	87.825	13.632	18.696						
2011	6	17.431	4.644	41.943	-32.656	18.798						
2011	7	16.059	4.148	41.545	-33.249	18.848						
2011	8	12.127	-0.005	37.426	-37.437	18.865						
2011	9	24.194	9.868	47.230	-27.493	18.829						
2011	10	30.148	33.016	70.248	-4.215	18.764						
2011	11	43.645	64.201	101.302	27.100	18.698						
2011	12	85.814	106.699	143.887	69.510	18.742						
2012	1	122.183	148.595	186.047	111.144	18.875						
2012	2	152.050	126.967	164.288	89.647	18.809						
2012	3	117.976	124.705	161.855	87.555	18.723						
2012	4	35.059	42.544	79.703	5.385	18.727						
2012	5	27.515	28.199	65.414	-9.016	18.756						
2012	6	18.490	0.486	37.900	-36.929	18.856						
2012	7	7.663	4.295	41.785	-33.194	18.894						
2012	8	7.506	-5.091	32.401	-42.582	18.895						
2012	9	9.643	7.152	44.600	-30.295	18.873						
2012	10	16.274	30.921	68.178	-6.335	18.777						
2012	11	44.986	56.931	94.072	19.789	18.719						
2012	12	89.842	102.467	139.645	65.289	18.737						
2013	1	183.515	184.029	221.767	146.292	19.019						
2013	2	203.740	167.221	204.722	129.720	18.900						
2013	3	169.938	176.384	213.767	139.000	18.841						
2013	4	134.718	127.932	165.202	90.661	18.784						
2013	5	82.608	66.882	104.053	29.710	18.734						
2013	6	22.414	24.387	61.773	-12.998	18.842						

Year	Month	Actual	Pred	Upper	Lower	Sigma	DOC Customer	MERC Customer	DOC Sales	MERC Sales	DOC Annual	MERC Annual
2013	7	12.768	-8.428	29.124	-45.980	18.925						
2013	8	11.859	8.622	46.167	-28.923	18.922						
2013	9	10.932	-0.778	36.750	-38.305	18.913						
2013	10	13.132	27.563	64.931	-9.805	18.833						
2013	11	53.548	73.153	110.324	35.982	18.734						
2013	12	145.002	140.402	177.809	102.996	18.852						
2014	1	272.818	221.724	260.406	183.042	19.495						
2014	2	283.842	273.570	312.468	234.671	19.604						
2014	3	243.402	226.004	264.685	187.323	19.495						
2014	4	140.294	161.292	199.520	123.063	19.266						
2014	5	75.090	76.093	114.298	37.889	19.254						
2014	6	27.883	36.007	74.479	-2.465	19.389						
2014	7	15.501	20.658	59.217	-17.901	19.433						
2014	8	15.076	21.608	60.178	-16.963	19.439						
2014	9	15.000	29.432	67.933	-9.069	19.404						
2014	10	22.415	55.975	94.276	17.675	19.303						
2014	11	56.022	92.713	130.888	54.539	19.239						
2014	12	178.453	162.723	201.126	124.320	19.354						
2015	1	217.314	211.473	249.971	172.975	19.402						
2015	2	215.609	203.191	241.674	164.708	19.395						
2015	3	241.171	212.990	251.513	174.467	19.415						
2015	4	111.586	142.998	181.174	104.821	19.240						
2015	5	57.293	51.838	90.116	13.560	19.291						
2015	6	15.147	45.796	84.256	7.336	19.383						
2015	7	7.647	5.058	43.654	-33.538	19.452						
2015	8		26.813	65.417	-11.791	19.456	1,414	1422.626743	37,908	38,144		
2015	9		31.789	70.338	-6.760	19.428	1,415	1423.795267	44,975	45,261		
2015	10		60.773	99.121	22.425	19.327	1,416	1425.057203	86,075	86,605		
2015	11		105.591	143.780	67.402	19.246	1,418	1426.493739	149,776	150,625		
2015	12		165.953	204.225	127.681	19.288	1,422	1427.661475	235,972	236,925		
2016	1		210.846	249.398	172.293	19.430	1,423	1428.853627	299,941	301,267		
2016	2		206.665	245.182	168.148	19.412	1,423	1430.04615	294,024	295,540		
2016	3		179.045	217.376	140.714	19.318	1,423	1431.218156	254,842	256,253		
2016	4		130.615	168.797	92.433	19.243	1,424	1432.466611	185,989	187,102		
2016	5		77.959	116.234	39.683	19.290	1,423	1433.79361	110,925	111,777		
2016	6		42.981	81.465	4.497	19.395	1,424	1435.556148	61,211	61,702		
2016	7		26.084	64.712	-12.544	19.468	1,422	1437.32229	37,098	37,492		
2016	8		24.700	63.343	-13.944	19.476	1,420	1439.261567	35,078	35,549		
2016	9		31.416	70.002	-7.171	19.447	1,422	1441.31171	44,673	45,280		
2016	10		60.400	98.775	22.024	19.340	1,425	1443.441419	86,043	87,183		
2016	11		105.217	143.417	67.017	19.252	1,428	1445.671101	150,208	152,110		
2016	12		165.579	203.840	127.319	19.283	1,432	1447.770097	237,077	239,721	1,797,109	1,810,974
2017	1		210.472	248.998	171.946	19.416	1,433	1449.880024	301,613	305,159		
2017	2		206.291	244.783	167.800	19.399	1,434	1451.987007	295,759	299,532		
2017	3		178.671	216.988	140.355	19.311	1,435	1454.08003	256,351	259,803		
2017	4		130.241	168.427	92.056	19.245	1,436	1456.207435	186,999	189,658		
2017	5		77.585	115.883	39.287	19.301	1,435	1458.370576	111,335	113,148		
2017	6		42.608	81.127	4.088	19.413	1,437	1460.747787	61,215	62,239		
2017	7		25.711	64.380	-12.959	19.489	1,435	1463.124301	36,898	37,618		
2017	8		24.326	63.012	-14.360	19.497	1,433	1465.585074	34,869	35,652		
2017	9		31.042	69.669	-7.585	19.467	1,436	1468.099534	44,566	45,573		
2017	10		60.026	98.432	21.620	19.356	1,439	1470.652513	86,351	88,277		
2017	11		104.844	143.058	66.629	19.259	1,442	1473.254583	151,178	154,461		
2017	12		165.206	203.458	126.953	19.279	1,446	1475.791172	238,946	243,809	1,806,080	1,834,928
2018	1		210.098	248.600	171.596	19.404	1,448	1478.333193	304,177	310,595		
2018	2		205.918	244.387	167.448	19.388	1,449	1480.874047	298,288	304,938		
2018	3		178.298	216.602	139.994	19.305	1,450	1483.408536	258,483	264,488		
2018	4		129.868	168.059	91.676	19.248	1,451	1485.961015	188,413	192,978		
2018	5		77.211	115.535	38.887	19.314	1,450	1488.532404	111,962	114,931		
2018	6		42.234	80.792	3.676	19.433	1,452	1491.211794	61,319	62,980		
2018	7		25.337	64.052	-13.378	19.511	1,450	1493.892367	36,748	37,851		
2018	8		23.952	62.684	-14.780	19.520	1,449	1496.616649	34,701	35,847		
2018	9		30.668	69.339	-8.002	19.489	1,451	1499.369576	44,503	45,983		
2018	10		59.652	98.091	21.213	19.372	1,454	1502.143748	86,739	89,606		
2018	11		104.470	142.701	66.239	19.268	1,458	1504.944575	152,270	157,222		
2018	12		164.832	203.080	126.584	19.276	1,462	1507.715097	240,989	248,520	1,818,591	1,865,939
2019	1		209.724	248.205	171.243	19.394	1,463	1510.49077	306,926	316,787		
2019	2		205.544	243.994	167.094	19.378	1,464	1513.268416	300,972	311,043		
2019	3		177.924	216.219	139.629	19.300	1,465	1516.045541	260,729	269,741		
2019	4		129.494	167.695	91.293	19.252	1,466	1518.834374	189,896	196,680		
2019	5		76.838	115.190	38.485	19.329	1,466	1521.635454	112,618	116,919		
2019	6		41.860	80.460	3.260	19.454	1,467	1524.49325	61,429	63,816		
2019	7		24.963	63.726	-13.799	19.536	1,466	1527.354601	36,595	38,128		
2019	8		23.579	62.359	-15.202	19.545	1,464	1530.240756	34,526	36,081		
2019	9		30.294	69.011	-8.422	19.513	1,467	1533.144263	44,431	46,446		
2019	10		59.279	97.754	20.803	19.391	1,470	1536.061483	87,117	91,055		
2019	11		104.096	142.348	65.845	19.278	1,473	1538.995155	153,342	160,204		
2019	12		164.458	202.705	126.212	19.275	1,478	1541.916932	242,992	253,581	1,831,574	1,900,479

Year	Month	Actual	Pred	Upper	Lower	Sigma	DOC Customer	MERC Customer	DOC Sales	MERC Sales	DOC Annual	MERC Annual
2020	1		209.351	247.814	170.888	19.385	1,479	1544.844516	309,615	323,414		
2020	2		205.170	243.604	166.736	19.370	1,480	1547.776353	303,584	317,557		
2020	3		177.550	215.840	139.261	19.297	1,481	1550.711227	262,904	275,329		
2020	4		129.120	167.333	90.907	19.259	1,482	1553.655254	191,318	200,608		
2020	5		76.464	114.848	38.079	19.345	1,481	1556.608721	113,231	119,024		
2020	6		41.487	80.131	2.842	19.476	1,483	1559.593805	61,508	64,702		
2020	7		24.590	63.403	-14.224	19.561	1,481	1562.584027	36,417	38,423		
2020	8		23.205	62.037	-15.627	19.571	1,479	1565.589988	34,326	36,329		
2020	9		29.921	68.687	-8.845	19.537	1,482	1568.607984	44,329	46,934		
2020	10		58.905	97.420	20.390	19.411	1,484	1571.636206	87,442	92,577		
2020	11		103.723	141.998	65.448	19.290	1,488	1574.676024	154,324	163,330		
2020	12		164.084	202.332	125.837	19.276	1,492	1577.713316	244,853	258,878	1,843,851	1,937,107
2021	1		208.977	247.425	170.529	19.377	1,494	1580.756905	312,119	330,342		
2021	2		204.796	250.446	159.147	23.006	1,494	1583.806015	306,008	324,358		
2021	3		177.177	222.713	131.640	22.950	1,495	1586.860038	264,910	281,155		
2021	4		128.747	174.234	83.259	22.925	1,496	1589.92202	192,613	204,697		
2021	5		76.090	121.738	30.442	23.006	1,495	1592.992099	113,762	121,211		
2021	6		41.113	86.991	-4.765	23.122	1,497	1596.081322	61,537	65,619		
2021	7		24.216	70.242	-21.810	23.196	1,495	1599.176486	36,205	38,725		
2021	8		22.831	68.873	-23.211	23.204	1,493	1602.282869	34,093	36,582		
2021	9		29.547	75.532	-16.438	23.175	1,495	1605.398614	44,187	47,435		
2021	10		58.531	104.295	12.767	23.064	1,498	1608.522814	87,698	94,149		
2021	11		103.349	148.898	57.800	22.956	1,502	1611.656141	155,193	166,563		
2021	12		163.711	209.218	118.203	22.935	1,506	1614.791547	246,539	264,359	1,854,865	1,975,195
2022	1		208.603	254.266	162.941	23.013	1,507	1617.933419	314,403	337,506		
2022	2		204.423	250.064	158.782	23.002	1,508	1621.081359	308,218	331,386		
2022	3		176.803	222.340	131.266	22.950	1,509	1624.235053	266,730	287,170		
2022	4		128.373	173.876	82.870	22.933	1,509	1627.396005	193,770	208,913		
2022	5		75.716	121.396	30.036	23.022	1,508	1630.564273	114,209	123,461		
2022	6		40.739	86.660	-5.182	23.143	1,510	1633.745348	61,515	66,557		
2022	7		23.842	69.916	-22.231	23.220	1,508	1636.932639	35,959	39,028		
2022	8		22.457	68.548	-23.633	23.229	1,506	1640.128761	33,828	36,833		
2022	9		29.173	75.205	-16.858	23.199	1,508	1643.332776	44,006	47,942		
2022	10		58.157	103.960	12.355	23.084	1,511	1646.544218	87,888	95,759		
2022	11		102.975	148.549	57.402	22.968	1,514	1649.763407	155,952	169,885		
2022	12		163.337	208.851	117.823	22.938	1,519	1652.986818	248,059	269,994	1,864,536	2,014,434
2023	1		208.230	253.885	162.575	23.009	1,520	1656.216621	316,480	344,874		
2023	2		204.049	249.684	158.414	22.999	1,520	1659.452604	310,226	338,610		
2023	3		176.429	221.969	130.890	22.951	1,521	1662.694596	268,377	293,348		
2023	4		127.999	173.520	82.478	22.942	1,522	1665.943331	194,800	213,239		
2023	5		75.343	121.057	29.628	23.039	1,521	1669.198823	114,578	125,762		
2023	6		40.365	86.331	-5.600	23.166	1,522	1672.463793	61,448	67,510		
2023	7		23.468	69.592	-22.655	23.246	1,520	1675.734942	35,682	39,327		
2023	8		22.084	68.225	-24.058	23.254	1,518	1679.013558	33,534	37,079		
2023	9		28.800	74.880	-17.281	23.224	1,521	1682.299158	43,791	48,450		
2023	10		57.784	103.627	11.941	23.104	1,523	1685.591494	88,018	97,400		
2023	11		102.602	148.203	57.001	22.982	1,526	1688.890711	156,613	173,283		
2023	12		162.963	208.486	117.441	22.942	1,531	1692.195037	249,430	275,766	1,872,977	2,054,647
2024	1		207.856	253.506	162.206	23.007	1,532	1695.505537	318,370	352,421		
2024	2		203.675	249.307	158.044	22.997	1,532	1698.822092	312,052	346,008		
2024	3		176.056	221.601	130.511	22.954	1,533	1702.1446	269,866	299,672		
2024	4		127.625	173.167	82.084	22.952	1,534	1705.473411	195,714	217,662		
2024	5		74.969	120.720	29.218	23.058	1,532	1708.808519	114,876	128,108		
2024	6		39.992	86.005	-6.022	23.190	1,534	1712.151262	61,338	68,472		
2024	7		23.095	69.272	-23.082	23.272	1,532	1715.499982	35,378	39,619		
2024	8		21.710	67.905	-24.485	23.281	1,530	1718.855306	33,213	37,317		
2024	9		28.426	74.558	-17.706	23.250	1,532	1722.216977	43,544	48,956		
2024	10		57.410	103.296	11.524	23.126	1,534	1725.584858	88,093	99,066		
2024	11		102.228	147.859	56.597	22.997	1,538	1728.959005	157,184	176,748		
2024	12		162.590	208.124	117.056	22.948	1,542	1732.338519	250,663	281,660	1,880,291	2,095,709
2025	1		207.482	253.130	161.835	23.006	1,543	1735.723917	320,088	360,132		
2025	2		203.302	248.932	157.671	22.997	1,543	1739.115125	313,711	353,565		
2025	3		175.682	221.235	130.129	22.958	1,544	1742.512076	271,210	306,128		
2025	4		127.252	172.816	81.687	22.964	1,544	1745.91493	196,521	222,171		
2025	5		74.595	120.386	28.805	23.078	1,543	1749.32367	115,107	130,492		
2025	6		39.618	85.682	-6.446	23.215	1,544	1752.738947	61,190	69,440		
2025	7		22.721	68.953	-23.511	23.300	1,543	1756.15992	35,048	39,902		
2025	8		21.336	67.587	-24.915	23.310	1,540	1759.586888	32,867	37,543		
2025	9		28.052	74.239	-18.134	23.277	1,542	1763.019707	43,267	49,457		
2025	10		57.036	102.968	11.104	23.149	1,545	1766.458295	88,117	100,752		
2025	11		101.854	147.517	56.191	23.013	1,548	1769.902665	157,670	180,272		
2025	12		162.216	207.764	116.668	22.955	1,552	1773.352356	251,767	287,666	1,886,563	2,137,521

Year	Month	Actual	Pred	Upper	Lower	Sigma	DOC Cus	MERC Customer	DOC Sales	MERC Sales	DOC Sales Annual	MERC Sales Annual
2007	1	129.008										
2007	2	176.629	181.2529298	197.2031775	165.302682	8.032208288						
2007	3	139.940	137.6099556	153.5271693	121.6927419	8.015573028						
2007	4	84.342	82.64220094	98.14624872	67.13815316	7.807511392						
2007	5	45.856	43.51636792	59.439801	27.59293484	8.018704984						
2007	6	23.545	22.91157268	38.82910944	6.994035925	8.01573572						
2007	7	19.530	18.41415743	34.33149534	2.496819518	8.015635586						
2007	8	17.893	16.83509192	32.81301163	0.857172219	8.046143299						
2007	9	19.330	16.66339255	32.64109573	0.685689374	8.046034259						
2007	10	22.609	18.68282923	34.11073447	3.254923992	7.769167617						
2007	11	52.054	58.5120404	73.97617229	43.04790851	7.787410592						
2007	12	129.412	129.4016323	145.020783	113.7824816	7.865474793						
2008	1	162.837	163.6379891	179.3737587	147.9022196	7.92420159						
2008	2	182.263	172.0369179	187.98987	156.0839658	8.033570142						
2008	3	154.838	151.067017	166.9856012	135.1484328	8.016263209						
2008	4	97.891	95.57797688	111.1090657	80.04688808	7.821128684						
2008	5	59.603	59.01838466	74.93793582	43.09883349	8.016750133						
2008	6	29.386	29.73019761	45.64759659	13.81279863	8.015666338						
2008	7	19.690	18.58228827	34.49962261	2.664953929	8.015633788						
2008	8	17.922	16.54930038	32.52722524	0.571375528	8.046145892						
2008	9	17.852	19.01610649	34.99377669	3.038436292	8.046017653						
2008	10	24.452	24.01780896	39.44835271	8.587265214	7.770496314						
2008	11	54.601	62.48173166	77.95139558	47.01206774	7.790196409						
2008	12	126.886	130.8996628	146.523247	115.2760786	7.867707418						
2009	1	192.953	168.8689973	184.6244674	153.1135272	7.934122379						
2009	2	166.428	167.7521337	183.7067486	151.7975188	8.034407503						
2009	3	131.557	133.0174692	148.9351799	117.0997585	8.015823322						
2009	4	92.036	88.52976743	104.0454372	73.0140977	7.813363962						
2009	5	49.675	51.87479811	67.79544789	35.95414832	8.017303377						
2009	6	27.008	32.2817525	48.19936382	16.36414118	8.015773268						
2009	7	21.264	22.60581363	38.52323407	6.688393191	8.015677144						
2009	8	18.922	19.64886258	35.62682805	3.670897102	8.046166347						
2009	9	18.815	18.16733117	34.14499898	2.189663355	8.046016451						
2009	10	34.246	37.83433461	53.27495673	22.39371249	7.775571569						
2009	11	61.353	67.54968604	83.02693631	52.07243578	7.79401673						
2009	12	99.621	105.074218	120.6270431	89.52139287	7.832074643						
2010	1	178.331	173.6849509	189.4592729	157.9106289	7.943615782						
2010	2	153.689	160.4115405	176.3706498	144.4524311	8.036670798						
2010	3	125.407	134.9253753	150.8428332	119.0079174	8.015695992						
2010	4	68.987	63.83915704	79.31050088	48.36781321	7.791042376						
2010	5	39.704	45.93032735	61.85276481	30.0078899	8.018203607						
2010	6	26.612	24.752165	40.66957202	8.834757975	8.015670387						
2010	7	19.495	18.76470972	34.68203936	2.84738008	8.01563142						
2010	8	17.050	16.38082083	32.35874984	0.402891826	8.046147984						
2010	9	17.976	18.67535483	34.6530219	2.697687765	8.046016076						
2010	10	23.850	25.98843933	41.42014765	10.55673101	7.771082768						
2010	11	44.327	58.94655919	74.41110357	43.48201481	7.787618315						
2010	12	122.572	131.8381005	147.4640833	116.2121177	7.868915292						
2011	1	175.351	145.6850227	161.3559061	130.0141392	7.891526331						
2011	2	162.377	164.5807875	180.5369963	148.6245786	8.035210178						
2011	3	130.116	133.0510787	148.9687877	117.1333697	8.015822446						
2011	4	92.087	91.33749165	106.8589963	75.81598697	7.81630232						
2011	5	60.689	62.00911474	77.9285488	46.08968069	8.016691158						
2011	6	28.455	28.13875248	44.05608881	12.22141615	8.015634789						
2011	7	19.136	20.7711959	36.68853578	4.853856012	8.01563658						
2011	8	16.674	16.38244927	32.3603796	0.404518936	8.046148649						
2011	9	18.225	18.86421686	34.84188516	2.886548559	8.046016697						
2011	10	24.203	26.05104823	41.48279579	10.61930066	7.771102532						
2011	11	48.470	61.37056921	76.83854323	45.9025952	7.789345407						
2011	12	104.162	106.5218038	122.0778204	90.96578718	7.833681809						
2012	1	123.232	141.0603151	156.7163596	125.4042706	7.88405372						
2012	2	139.493	136.6250491	152.6070411	120.6430572	8.04819399						
2012	3	109.457	101.8073983	117.7411412	85.87365543	8.023896776						
2012	4	48.045	45.55469955	61.00305869	30.10634042	7.779467769						
2012	5	41.802	44.04038683	59.96359294	28.11718073	8.018590685						
2012	6	22.644	22.23534537	38.15296523	6.317725514	8.015777567						
2012	7	17.719	18.30631641	34.22365734	2.38897549	8.015637103						
2012	8	15.895	17.20745978	33.18537581	1.229543742	8.046141449						
2012	9	16.567	16.71066459	32.68836799	0.732961192	8.046034372						
2012	10	28.090	31.17992739	46.61513437	15.74472042	7.772844615						
2012	11	56.252	62.23815525	77.70734549	46.76896501	7.789957871						
2012	12	89.906	98.40712676	113.9441422	82.87011132	7.824113213						
2013	1	153.942	166.1725393	181.9172104	150.4278681	7.928684264						
2013	2	159.399	155.6630343	171.6258588	139.7002099	8.038541643						
2013	3	136.435	138.4047795	154.3219474	122.4876116	8.015549968						
2013	4	108.667	116.3881504	131.9704037	100.8058972	7.846894037						
2013	5	78.656	68.58397895	84.50384022	52.66411767	8.016906298						
2013	6	30.692	32.88604139	48.80376263	16.96832016	8.01582862						
2013	7	19.948	19.25656384	35.17388847	3.339239207	8.015628898						
2013	8	17.275	18.91666495	34.89460282	2.938727069	8.046152449						
2013	9	17.199	15.67247904	31.65023768	-0.305279601	8.04606219						
2013	10	20.429	23.56794235	38.99826914	8.137615554	7.770387061						
2013	11	62.704	75.81556089	91.30670472	60.32441706	7.801013236						
2013	12	120.811	134.4283838	150.0624647	118.7943029	7.872993316						
2014	1	194.165	160.9692949	176.6939361	145.2446537	7.918597579						
2014	2	192.948	186.9098848	202.8592898	170.9604797	8.031783931						
2014	3	166.784	167.0036621	182.9291611	151.0781632	8.019745321						

Year	Month	Actual	Pred	Upper	Lower	Sigma	DOC Cus	MERC Customer	DOC Sales	MERC Sales	DOC Sales Annual	MERC Sales Annual
2014	4	107.765	103.7870162	119.3370237	88.23700867	7.83065576						
2014	5	64.121	64.45423901	80.37373058	48.53474745	8.01672012						
2014	6	30.790	25.11934493	41.03672469	9.20196517	8.015656659						
2014	7	19.818	19.61374255	35.53106602	3.696419081	8.015628312						
2014	8	17.668	17.38729941	33.36521447	1.409384347	8.046140959						
2014	9	17.275	19.10290034	35.08057139	3.125229294	8.04601808						
2014	10	27.963	34.71260389	50.15051618	19.2746916	7.774206957						
2014	11	57.977	75.77087534	91.26179819	60.27995249	7.800901956						
2014	12	128.941	135.5534871	151.1907598	119.9162143	7.874600696						
2015	1	155.642	146.4869554	162.1607576	130.8131532	7.892996143						
2015	2	146.792	154.7772382	170.74038	138.8140963	8.038701494						
2015	3	157.693	155.6882881	171.6081527	139.7684235	8.016907979						
2015	4	86.188	82.9630716	98.46773146	67.45841173	7.807819627						
2015	5	49.861	50.5384927	66.45947977	34.61750562	8.017473229						
2015	6	28.856	29.93282302	45.85023223	14.0154138	8.015671492						
2015	7	19.405	19.68987027	35.6071935	3.772547042	8.015628192						
2015	8		17.70377051	33.68168579	1.725855218	8.046141073	40,764	41,018	721,675	726,177		
2015	9		17.74102132	33.71869412	1.763348512	8.046018965	40,828	41,088	724,325	728,936		
2015	10		30.93760106	46.37263291	15.50256921	7.772756428	40,903	41,155	1,265,428	1,273,229		
2015	11		67.94797447	83.42598669	52.46996224	7.794400437	40,993	41,225	2,785,358	2,801,149		
2015	12		117.7857329	133.3719245	102.1995413	7.848877296	41,107	41,273	4,841,861	4,861,416		
2016	1		154.8578671	170.5613316	139.1544026	7.90793345	41,135	41,317	6,370,153	6,398,315		
2016	2		161.4005233	177.3590545	145.4419922	8.036379649	41,144	41,356	6,640,616	6,674,855		
2016	3		134.6838048	150.6012732	118.7663364	8.015701313	41,160	41,388	5,543,617	5,574,312		
2016	4		88.72679197	104.2429367	73.21064722	7.813603173	41,174	41,420	3,653,214	3,675,073		
2016	5		55.05879599	70.97882452	39.13876746	8.016990523	41,136	41,452	2,264,916	2,282,310		
2016	6		30.92573726	46.84321964	15.00825487	8.015708338	41,175	41,505	1,273,365	1,283,577		
2016	7		20.33286775	36.25019757	4.415537935	8.015631509	41,118	41,555	836,046	844,923		
2016	8		17.69788041	33.67579569	1.719965121	8.046141073	41,059	41,610	726,650	736,416		
2016	9		17.74115453	33.71882733	1.763481725	8.046018965	41,111	41,669	729,365	739,264		
2016	10		30.93759805	46.3726299	15.50256619	7.772756428	41,184	41,730	1,274,145	1,291,029		
2016	11		67.94797454	83.42598676	52.46996231	7.794400437	41,271	41,794	2,804,300	2,839,800		
2016	12		117.7857329	133.3719245	102.1995413	7.848877296	41,386	41,847	4,874,673	4,929,035	36,991,060	37,268,908
2017	1		154.8578671	170.5613316	139.1544026	7.90793345	41,413	41,900	6,413,077	6,488,474		
2017	2		161.4005233	177.3590545	145.4419922	8.036379649	41,421	41,949	6,685,357	6,770,644		
2017	3		134.6838048	150.6012732	118.7663364	8.015701313	41,438	41,996	5,581,082	5,656,231		
2017	4		88.72679197	104.2429367	73.21064722	7.813603173	41,454	42,044	3,678,079	3,730,390		
2017	5		55.05879599	70.97882452	39.13876746	8.016990523	41,417	42,091	2,280,353	2,317,485		
2017	6		30.92573726	46.84321964	15.00825487	8.015708338	41,456	42,149	1,282,045	1,303,498		
2017	7		20.33286775	36.25019757	4.415537935	8.015631509	41,398	42,206	841,748	858,169		
2017	8		17.69788041	33.67579569	1.719965121	8.046141073	41,339	42,266	731,604	748,022		
2017	9		17.74115453	33.71882733	1.763481725	8.046018965	41,393	42,328	734,366	750,951		
2017	10		30.93759805	46.3726299	15.50256619	7.772756428	41,466	42,391	1,282,873	1,311,485		
2017	11		67.94797454	83.42598676	52.46996231	7.794400437	41,554	42,456	2,823,486	2,884,808		
2017	12		117.7857329	133.3719245	102.1995413	7.848877296	41,668	42,516	4,907,930	5,007,812	37,242,001	37,827,968
2018	1		154.8578671	170.5613316	139.1544026	7.90793345	41,696	42,576	6,456,965	6,593,208		
2018	2		161.4005233	177.3590545	145.4419922	8.036379649	41,705	42,635	6,731,177	6,881,240		
2018	3		134.6838048	150.6012732	118.7663364	8.015701313	41,723	42,692	5,619,381	5,749,939		
2018	4		88.72679197	104.2429367	73.21064722	7.813603173	41,739	42,750	3,703,338	3,793,073		
2018	5		55.05879599	70.97882452	39.13876746	8.016990523	41,702	42,808	2,296,072	2,356,977		
2018	6		30.92573726	46.84321964	15.00825487	8.015708338	41,742	42,872	1,290,888	1,325,855		
2018	7		20.33286775	36.25019757	4.415537935	8.015631509	41,685	42,936	847,577	873,004		
2018	8		17.69788041	33.67579569	1.719965121	8.046141073	41,626	43,001	736,691	761,026		
2018	9		17.74115453	33.71882733	1.763481725	8.046018965	41,681	43,068	739,469	764,067		
2018	10		30.93759805	46.3726299	15.50256619	7.772756428	41,755	43,135	1,291,793	1,334,487		
2018	11		67.94797454	83.42598676	52.46996231	7.794400437	41,843	43,203	2,843,125	2,935,570		
2018	12		117.7857329	133.3719245	102.1995413	7.848877296	41,958	43,270	4,942,095	5,096,531	37,498,572	38,464,978
2019	1		154.8578671	170.5613316	139.1544026	7.90793345	41,987	43,336	6,501,996	6,710,885		
2019	2		161.4005233	177.3590545	145.4419922	8.036379649	41,996	43,402	6,778,257	7,005,078		
2019	3		134.6838048	150.6012732	118.7663364	8.015701313	42,015	43,468	5,658,783	5,854,376		
2019	4		88.72679197	104.2429367	73.21064722	7.813603173	42,032	43,534	3,729,372	3,862,605		
2019	5		55.05879599	70.97882452	39.13876746	8.016990523	41,996	43,600	2,312,273	2,400,578		
2019	6		30.92573726	46.84321964	15.00825487	8.015708338	42,037	43,670	1,300,015	1,350,522		
2019	7		20.33286775	36.25019757	4.415537935	8.015631509	41,981	43,739	853,597	889,347		
2019	8		17.69788041	33.67579569	1.719965121	8.046141073	41,923	43,810	741,944	775,347		
2019	9		17.74115453	33.71882733	1.763481725	8.046018965	41,979	43,882	744,748	778,513		
2019	10		30.93759805	46.3726299	15.50256619	7.772756428	42,053	43,954	1,301,015	1,359,829		
2019	11		67.94797454	83.42598676	52.46996231	7.794400437	42,141	44,027	2,863,414	2,991,537		
2019	12		117.7857329	133.3719245	102.1995413	7.848877296	42,257	44,099	4,977,330	5,194,236	37,762,744	39,172,852
2020	1		154.8578671	170.5613316	139.1544026	7.90793345	42,287	44,171	6,548,427	6,840,283		
2020	2		161.4005233	177.3590545	145.4419922	8.036379649	42,297	44,244	6,826,744	7,140,977		
2020	3		134.6838048	150.6012732	118.7663364	8.015701313	42,316	44,316	5,699,321	5,968,694		
2020	4		88.72679197	104.2429367	73.21064722	7.813603173	42,334	44,389	3,756,126	3,938,518		
2020	5		55.05879599	70.97882452	39.13876746	8.016990523	42,298	44,463	2,328,900	2,448,060		
2020	6		30.92573726	46.84321964	15.00825487	8.015708338	42,339	44,538	1,309,363	1,377,362		
2020	7		20.33286775	36.25019757	4.415537935	8.015631509	42,284	44,613	859,746	907,111		
2020	8		17.69788041	33.67579569	1.719965121	8.046141073	42,225	44,689	747,299	790,903		
2020	9		17.74115453	33.71882733	1.763481725	8.046018965	42,281	44,766	750,119	794,198		
2020	10		30.93759805	46.3726299	15.50256619	7.772756428	42,356	44,843	1,310,385	1,387,338		
2020	11		67.94797454	83.42598676	52.46996231	7.794400437	42,444	44,921	2,884,001	3,052,287		
2020	12		117.7857329	133.3719245	102.1995413	7.848877296	42,561	44,999	5,013,033	5,300,192	38,033,465	39,945,924
2021	1		154.8578671	170.5613316	139.1544026	7.90793345	42,590	45,077	6,595,387	6,980,456		
2021	2		161.4005233	177.3628665	145.4381801	8.038299294	42,600	45,155	6,875,702	7,288,000		
2021	3		134.6838048	150.605097	118.7625126	8.017626893	42,620	45,233	5,740,184	6,092,179		
2021	4		88.72679197	104.2468594	73.20672456	7.815578546	42,637	45,312	3,783,048	4,020,394		
2021	5		55.05879599	70.98264769	39.13494428	8.018915794	42,602	45,391	2,345,610	2,499,193		
2021	6		30.92573726	46.84704343	15.00443109	8.017633916	42,643	45,472	1,318,752	1,406,245		

Year	Month	Actual	Pred	Upper	Lower	Sigma	DOC Cus	MERC Customer	DOC Sales	MERC Sales	DOC Sales Annual	MERC Sales Annual
2021	7		20.33286775	36.25402139	4.411714112	8.017557106	42,587	45,552	865,922	926,209		
2021	8		17.69788041	33.67960502	1.716155793	8.048059371	42,529	45,634	752,677	807,618		
2021	9		17.74115453	33.72263672	1.759672339	8.047937291	42,585	45,715	755,512	811,043		
2021	10		30.93759805	46.37657317	15.49862292	7.774742179	42,660	45,798	1,319,792	1,416,866		
2021	11		67.94797454	83.42991909	52.46602998	7.796380676	42,748	45,880	2,904,666	3,117,470		
2021	12		117.7857329	133.3758296	102.1956362	7.850843793	42,865	45,963	5,048,863	5,413,792	38,306,114	40,779,465
2022	1		154.8578671	170.5652075	139.1505267	7.909885266	42,894	46,046	6,642,504	7,130,617		
2022	2		161.4005233	177.3628685	145.4381782	8.038300276	42,905	46,130	6,924,823	7,445,355		
2022	3		134.6838048	150.605097	118.7625126	8.017626893	42,924	46,213	5,781,190	6,224,206		
2022	4		88.72679197	104.2468594	73.20672456	7.815578546	42,942	46,298	3,810,074	4,107,843		
2022	5		55.05879599	70.98264769	39.13494428	8.018915794	42,907	46,382	2,362,388	2,553,750		
2022	6		30.92573726	46.84704343	15.00443109	8.017633916	42,947	46,468	1,328,180	1,437,043		
2022	7		20.33286775	36.25402139	4.411714112	8.017557106	42,892	46,553	872,123	946,560		
2022	8		17.69788041	33.67960502	1.716155793	8.048059371	42,834	46,639	758,075	825,417		
2022	9		17.74115453	33.72263672	1.759672339	8.047937291	42,890	46,726	760,924	828,971		
2022	10		30.93759805	46.37657317	15.49862292	7.774742179	42,965	46,813	1,329,234	1,448,278		
2022	11		67.94797454	83.42991909	52.46602998	7.796380676	43,054	46,900	2,925,414	3,186,780		
2022	12		117.7857329	133.3758296	102.1956362	7.850843793	43,170	46,988	5,084,859	5,534,509	38,579,788	41,669,329
2023	1		154.8578671	170.5652075	139.1505267	7.909885266	43,200	47,076	6,689,879	7,290,079		
2023	2		161.4005233	177.3628685	145.4381782	8.038300276	43,211	47,164	6,974,242	7,612,340		
2023	3		134.6838048	150.605097	118.7625126	8.017626893	43,231	47,253	5,822,457	6,364,209		
2023	4		88.72679197	104.2468594	73.20672456	7.815578546	43,248	47,342	3,837,275	4,200,506		
2023	5		55.05879599	70.98264769	39.13494428	8.018915794	43,213	47,431	2,379,275	2,611,519		
2023	6		30.92573726	46.84704343	15.00443109	8.017633916	43,254	47,521	1,337,672	1,469,635		
2023	7		20.33286775	36.25402139	4.411714112	8.017557106	43,199	47,612	878,367	968,083		
2023	8		17.69788041	33.67960502	1.716155793	8.048059371	43,142	47,702	763,514	844,233		
2023	9		17.74115453	33.72263672	1.759672339	8.047937291	43,198	47,794	766,381	847,914		
2023	10		30.93759805	46.37657317	15.49862292	7.774742179	43,273	47,885	1,338,756	1,481,451		
2023	11		67.94797454	83.42991909	52.46602998	7.796380676	43,362	47,977	2,946,339	3,259,942		
2023	12		117.7857329	133.3758296	102.1956362	7.850843793	43,479	48,069	5,121,147	5,661,867	38,855,304	42,611,780
2024	1		154.8578671	170.5652075	139.1505267	7.909885266	43,508	48,162	6,737,608	7,458,225		
2024	2		161.4005233	177.3628685	145.4381782	8.038300276	43,519	48,255	7,024,005	7,788,321		
2024	3		134.6838048	150.605097	118.7625126	8.017626893	43,539	48,348	5,864,002	6,511,669		
2024	4		88.72679197	104.2468594	73.20672456	7.815578546	43,557	48,441	3,864,662	4,298,050		
2024	5		55.05879599	70.98264769	39.13494428	8.018915794	43,522	48,535	2,396,277	2,672,296		
2024	6		30.92573726	46.84704343	15.00443109	8.017633916	43,563	48,630	1,347,224	1,503,908		
2024	7		20.33286775	36.25402139	4.411714112	8.017557106	43,508	48,724	884,648	990,706		
2024	8		17.69788041	33.67960502	1.716155793	8.048059371	43,451	48,819	768,982	864,000		
2024	9		17.74115453	33.72263672	1.759672339	8.047937291	43,507	48,915	771,865	867,806		
2024	10		30.93759805	46.37657317	15.49862292	7.774742179	43,582	49,011	1,348,326	1,516,271		
2024	11		67.94797454	83.42991909	52.46602998	7.796380676	43,671	49,107	2,967,373	3,336,705		
2024	12		117.7857329	133.3758296	102.1956362	7.850843793	43,788	49,203	5,157,628	5,795,434	39,132,601	43,603,392
2025	1		154.8578671	170.5652075	139.1505267	7.909885266	43,818	49,300	6,785,587	7,634,487		
2025	2		161.4005233	177.3628685	145.4381782	8.038300276	43,829	49,397	7,074,022	7,972,711		
2025	3		134.6838048	150.605097	118.7625126	8.017626893	43,849	49,494	5,905,748	6,666,105		
2025	4		88.72679197	104.2468594	73.20672456	7.815578546	43,867	49,592	3,892,164	4,400,161		
2025	5		55.05879599	70.98264769	39.13494428	8.018915794	43,832	49,690	2,413,344	2,735,890		
2025	6		30.92573726	46.84704343	15.00443109	8.017633916	43,873	49,789	1,356,812	1,539,755		
2025	7		20.33286775	36.25402139	4.411714112	8.017557106	43,818	49,888	890,952	1,014,358		
2025	8		17.69788041	33.67960502	1.716155793	8.048059371	43,761	49,987	774,469	884,659		
2025	9		17.74115453	33.72263672	1.759672339	8.047937291	43,817	50,086	777,366	888,586		
2025	10		30.93759805	46.37657317	15.49862292	7.774742179	43,892	50,186	1,357,921	1,552,633		
2025	11		67.94797454	83.42991909	52.46602998	7.796380676	43,981	50,286	2,988,449	3,416,836		
2025	12		117.7857329	133.3758296	102.1956362	7.850843793	44,098	50,386	5,194,171	5,934,808	39,411,006	44,640,990

MERC System Dead-Weight Loss Calculations

	MERC Filed	DOC Alternative 1.5% Growth	DOC Alternative 1% Growth	Per therm rate	per dekatherm rate		Months	Dead-Weight Loss MERC	DW Loss DOC 1.5%	DW Loss DOC 1%
2016							12			
2017				0.00304	0.0304		12			
2018				0.0181	0.181		12			
2019	29,017	27,115	30,886	0.02099	0.2099	30	12	$2,192,622	$2,048,940	$2,333,898
2020	27,964	25,400	30,491	0.0358	0.358	30	12	$3,604,057	$3,273,597	$3,929,724
2021	25,413	22,172	28,615	0.0356	0.356	30	12	$3,256,985	$2,841,549	$3,667,325
2022	22,824	18,890	26,719	0.03525	0.3525	30	12	$2,896,385	$2,397,150	$3,390,611
2023	20,196	15,554	24,802	0.0349	0.349	30	12	$2,537,430	$1,954,212	$3,116,098
2024	17,528	12,163	22,864	0.0344	0.344	30	12	$2,170,729	$1,506,267	$2,831,490
2025	14,821	8,716	20,905	0.03418	0.3418	30	12	$1,823,687	$1,072,492	$2,572,371
2026	12,073	5,212	18,926	0.03381	0.3381	30	12	$1,469,450	$634,421	$2,303,546
2027	9,283	1,651	16,924	0.03345	0.3345	30	12	$1,117,906	$198,799	$2,038,027
2028	6,452		14,901	0.03295	0.3295	30	12	$765,355		$1,767,608
2029	3,578		12,857	0.03272	0.3272	30	12	$421,514		$1,514,415
2030	662		10,790	0.03236	0.3236	30	12	$77,080		$1,256,973
2031			8,701	0.03236	0.3236	30	12			$1,013,593
2032			6,589	0.03236	0.3236	30	12			$767,585
2033			4,454	0.03236	0.3236	30	12			$518,920
2034			2,297	0.03236	0.3236	30	12			$267,571
2035				0.03236	0.3236	30	12			
2036				0.03236	0.3236	30	12			
2037				0.03236	0.3236	30	12			
2038				0.03236	0.3236	30	12			
2039				0.03236	0.3236	30	12			
2040				0.03236	0.3236	30	12			
					Total Loss through 2040			$22,333,201	$15,927,427	$33,289,756

MERC Rochester Dead-Weight Loss Calculations

	MERC Filed	DOC Rochester Growth	Per therm rate	per dekatherm rate	Months		Dead-Weight Loss MERC	DW Loss DOC
2016						12		
2017			0.00304	0.0304	30	12		
2018			0.0181	0.181	30	12		
2019	0	0	0.02099	0.2099	30	12	$0	$0
2020	16,910	19,474	0.0358	0.358	30	12	$2,179,361	$2,509,822
2021	15,557	18,798	0.0356	0.356	30	12	$1,993,753	$2,409,189
2022	14,183	18,117	0.03525	0.3525	30	12	$1,799,848	$2,299,083
2023	12,789	17,431	0.0349	0.349	30	12	$1,606,815	$2,190,032
2024	11,374	16,739	0.0344	0.344	30	12	$1,408,552	$2,073,014
2025	9,938	16,043	0.03418	0.3418	30	12	$1,222,811	$1,974,006
2026	8,480	15,340	0.03381	0.3381	30	12	$1,032,131	$1,867,161
2027	7,000	14,633	0.03345	0.3345	30	12	$842,955	$1,762,062
2028	5,498	13,920	0.03295	0.3295	30	12	$652,199	$1,651,131
2029	3,974	13,201	0.03272	0.3272	30	12	$468,081	$1,554,957
2030	2,426	12,477	0.03236	0.3236	30	12	$282,677	$1,453,486
2031	856	11,747	0.03236	0.3236	30	12	$99,719	$1,368,472
2032		11,012	0.03236	0.3236	30	12		$1,282,803
2033		10,271	0.03236	0.3236	30	12		$1,196,474
2034		9,524	0.03236	0.3236	30	12		$1,109,479
2035		8,771	0.03236	0.3236	30	12		$1,021,813
2036		8,013	0.03236	0.3236	30	12		$933,472
2037		7,249	0.03236	0.3236	30	12		$844,449
2038		6,479	0.03236	0.3236	30	12		$754,740
2039		5,703	0.03236	0.3236	30	12		$664,339
2040		4,921	0.03236	0.3236	30	12		$573,242
				Total Loss through 2040			$13,588,903	$31,493,227

Total Dead Weight Loss and Excess Capacity Cost

	MERC Excess Capacity	DOC Excess Capacity
2016		
2017		
2018		
2019	29,017	30,886
2020	44,874	49,965
2021	40,970	47,413
2022	37,007	44,836
2023	32,985	42,233
2024	28,902	39,604
2025	24,759	36,948
2026	20,553	34,266
2027	16,284	31,557
2028	11,950	28,821
2029	7,552	26,058
2030	3,088	23,267
2031	856	20,448
2032		17,601
2033		14,725
2034		11,821
2035		8,771
2036		8,013
2037		7,249
2038		6,479
2039		5,703
2040		4,921

		MERC Excess Capacity	DOC Excess Capacity
	2016		
	2017		
	2018		
	2019	$2,192,622	$2,333,898
	2020	$5,783,419	$6,439,545
	2021	$5,250,738	$6,076,514
	2022	$4,696,232	$5,689,694
	2023	$4,144,245	$5,306,131
	2024	$3,579,281	$4,904,504
	2025	$3,046,498	$4,546,377
	2026	$2,501,582	$4,170,707
	2027	$1,960,861	$3,800,089
	2028	$1,417,554	$3,418,740
	2029	$889,595	$3,069,372
	2030	$359,757	$2,710,459
	2031	$99,719	$2,382,066
	2032	$0	$2,050,388
	2033	$0	$1,715,394
	2034	$0	$1,377,050
	2035	$0	$1,021,813
	2036	$0	$933,472
	2037	$0	$844,449
	2038	$0	$754,740
	2039	$0	$664,339
	2040	$0	$573,242
Total		$35,922,104	$64,782,983

MERC System Dead-Weight Loss Calculations

	MERC Filed	DOC Alternative	DOC 1% Growth	Per therm rate	per dekatherm rate		Months	Dead-Weight Loss MERC	DW Loss DOC	DW Loss DOC 1%
2016							12			
2017				0.00304	0.0304		12			
2018				0.0181	0.181		12			
2019	19,654	17,752	17,752	0.02099	0.2099	30	12	$1,485,123	$1,341,440	$1,341,440
2020	13,021	10,457	10,457	0.0358	0.358	30	12	$1,678,202	$1,347,742	$1,347,742
2021	11,823	8,581	8,581	0.0356	0.356	30	12	$1,515,204	$1,099,767	$1,099,767
2022	10,619	6,685	6,685	0.03525	0.3525	30	12	$1,347,532	$848,297	$848,297
2023	9,410	4,768	4,768	0.0349	0.349	30	12	$1,182,244	$599,027	$599,027
2024	8,196	2,830	2,830	0.0344	0.344	30	12	$1,014,941	$350,479	$350,479
2025	6,976	871	871	0.03418	0.3418	30	12	$858,423	$107,228	$107,228
2026	5,752			0.03381	0.3381	30	12	$700,117	$0	$0
2027	4,523			0.03345	0.3345	30	12	$544,639	$0	$0
2028	3,289			0.03295	0.3295	30	12	$390,107	$0	$0
2029	2,050			0.03272	0.3272	30	12	$241,446	$0	$0
2030	806			0.03236	0.3236	30	12	$93,901	$0	$0
2031				0.03236	0.3236	30	12	$0		
2032				0.03236	0.3236	30	12	$0		
2033				0.03236	0.3236	30	12	$0		
2034				0.03236	0.3236	30	12	$0		
2035				0.03236	0.3236	30	12	$0		
2036				0.03236	0.3236	30	12	$0		
2037				0.03236	0.3236	30	12	$0		
2038				0.03236	0.3236	30	12	$0		
2039				0.03236	0.3236	30	12			
2040				0.03236	0.3236	30	12			
					Total Loss through 2040			$11,051,879	$5,693,980	$5,693,980

MERC Rochester Dead-Weight Loss Calculations

	MERC Filed	DOC Alternative	Per therm rate	per dekatherm rate	Months		Dead-Weight Loss MERC	DW Loss DOC
2016						12		
2017			0.00304	0.0304	30	12		
2018			0.0181	0.181	30	12		
2019	0	0	0.02099	0.2099	30	12	$0	$0
2020	910	3,474	0.0358	0.358	30	12	$117,281	$447,742
2021	0	2,798	0.0356	0.356	30	12	$0	$358,629
2022	0	2,117	0.03525	0.3525	30	12	$0	$268,683
2023	0	1,431	0.0349	0.349	30	12	$0	$179,792
2024	0	739	0.0344	0.344	30	12	$0	$91,574
2025	0	43	0.03418	0.3418	30	12	$0	$5,238
2026	0	0	0.03381	0.3381	30	12	$0	$0
2027		0	0.03345	0.3345	30	12	$0	$0
2028		0	0.03295	0.3295	30	12	$0	$0
2029		0	0.03272	0.3272	30	12	$0	$0
2030		0	0.03236	0.3236	30	12	$0	$0
2031		0	0.03236	0.3236	30	12	$0	$0
2032		0	0.03236	0.3236	30	12		$0
2033		0	0.03236	0.3236	30	12		$0
2034		0	0.03236	0.3236	30	12		$0
2035		0	0.03236	0.3236	30	12		$0
2036		0	0.03236	0.3236	30	12		$0
2037			0.03236	0.3236	30	12		$0
2038			0.03236	0.3236	30	12		$0
2039			0.03236	0.3236	30	12		$0
2040			0.03236	0.3236	30	12		$0
				Total Loss through 2040			$117,281	$1,351,658

Total Cost of Excess of Capacity

	MERC Excess	DOC Excess	MERC Cost of Excess Capacity	DOC Cost of Excess Capacity
2019	19,654	17,752	$1,485,123	$1,341,440
2020	13,931	13,931	$1,795,483	$1,795,483
2021	11,823	11,379	$1,515,204	$1,458,397
2022	10,619	8,802	$1,347,532	$1,116,979
2023	9,410	6,199	$1,182,244	$778,819
2024	8,196	3,570	$1,014,941	$442,053
2025	6,976	914	$858,423	$112,466
2026	5,752	0	$700,117	$0
2027	4,523	0	$544,639	$0
2028	3,289	0	$390,107	$0
2029	2,050	0	$241,446	$0
2030	806	0	$93,901	$0
2031	0	0	$0	$0
2032	0	0	$0	$0
2033	0	0	$0	$0
2034	0	0	$0	$0
2035	0	0	$0	$0
2036	0	0	$0	$0
2037	0	0	$0	$0
2038	0	0	$0	$0
2039	0	0	$0	$0
2040	0	0	$0	$0
			$11,169,161	$7,045,638

MERC System Dead-Weight Loss Calculations

	MERC Filed	DOC Alternative	DOC 1% Growth	Per therm rate	per dekatherm rate		Months	Dead-Weight Loss MERC	DW Loss DOC	DW Loss DOC 1%
2016							12			
2017				0.00304	0.0304		12			
2018				0.0181	0.181		12			
2019	19,654	17,752	17,752	0.02099	0.2099	30	12	$1,485,123	$1,341,440	$1,341,440
2020	13,021	10,457	10,457	0.0358	0.358	30	12	$1,678,202	$1,347,742	$1,347,742
2021	11,823	8,581	8,581	0.0356	0.356	30	12	$1,515,204	$1,099,767	$1,099,767
2022	10,619	6,685	6,685	0.03525	0.3525	30	12	$1,347,532	$848,297	$848,297
2023	9,410	4,768	4,768	0.0349	0.349	30	12	$1,182,244	$599,027	$599,027
2024	8,196	2,830	2,830	0.0344	0.344	30	12	$1,014,941	$350,479	$350,479
2025	6,976	871	871	0.03418	0.3418	30	12	$858,423	$107,228	$107,228
2026	5,752			0.03381	0.3381	30	12	$700,117	$0	$0
2027	4,523			0.03345	0.3345	30	12	$544,639	$0	$0
2028	3,289			0.03295	0.3295	30	12	$390,107	$0	$0
2029	2,050			0.03272	0.3272	30	12	$241,446	$0	$0
2030	806			0.03236	0.3236	30	12	$93,901	$0	$0
2031				0.03236	0.3236	30	12	$0		
2032				0.03236	0.3236	30	12	$0		
2033				0.03236	0.3236	30	12	$0		
2034				0.03236	0.3236	30	12	$0		
2035				0.03236	0.3236	30	12	$0		
2036				0.03236	0.3236	30	12	$0		
2037				0.03236	0.3236	30	12	$0		
2038				0.03236	0.3236	30	12	$0		
2039				0.03236	0.3236	30	12			
2040				0.03236	0.3236	30	12			
					Total Loss through 2040			$11,051,879	$5,693,980	$5,693,980

MERC Rochester Dead-Weight Loss Calculations

	MERC Filed	DOC Alternative	Per therm rate	per dekatherm rate	Months		Dead-Weight Loss MERC	DW Loss DOC
2016						12		
2017			0.00304	0.0304	30	12		
2018			0.0181	0.181	30	12		
2019	0	0	0.02099	0.2099	30	12	$0	$0
2020	8,910	11,474	0.0358	0.358	30	12	$1,148,321	$1,478,782
2021	7,557	10,798	0.0356	0.356	30	12	$968,473	$1,383,909
2022	6,183	10,117	0.03525	0.3525	30	12	$784,648	$1,283,883
2023	4,789	9,431	0.0349	0.349	30	12	$601,695	$1,184,912
2024	3,374	8,739	0.0344	0.344	30	12	$417,832	$1,082,294
2025	1,938	8,043	0.03418	0.3418	30	12	$238,427	$989,622
2026	480	7,340	0.03381	0.3381	30	12	$58,403	$893,433
2027		6,633	0.03345	0.3345	30	12	$0	$798,702
2028		5,920	0.03295	0.3295	30	12	$0	$702,171
2029		5,201	0.03272	0.3272	30	12	$0	$612,621
2030		4,477	0.03236	0.3236	30	12	$0	$521,518
2031		3,747	0.03236	0.3236	30	12	$0	$436,504
2032		3,012	0.03236	0.3236	30	12		$350,835
2033		2,271	0.03236	0.3236	30	12		$264,506
2034		1,524	0.03236	0.3236	30	12		$177,511
2035		771	0.03236	0.3236	30	12		$89,845
2036		13	0.03236	0.3236	30	12		$1,504
2037			0.03236	0.3236	30	12		$0
2038			0.03236	0.3236	30	12		$0
2039			0.03236	0.3236	30	12		$0
2040			0.03236	0.3236	30	12		$0
			Total Loss through 2040				$4,217,800	$12,252,553

	MERC Excess Capacity	DOC Excess Capacity
2019	19,654	17,752
2020	21,931	21,931
2021	19,379	19,379
2022	16,802	16,802
2023	14,199	14,199
2024	11,570	11,570
2025	8,914	8,914
2026	6,232	7,340
2027	4,523	6,633
2028	3,289	5,920
2029	2,050	5,201
2030	806	4,477
2031	0	3,747
2032	0	3,012
2033	0	2,271
2034	0	1,524
2035	0	771
2036	0	13
2037	0	0
2038	0	0
2039	0	0
2040	0	0

Total Cost of Excess Capacity

		MERC Cost of Excess Capacity	DOC Cost of Excess Capacity
	2019	$1,485,123	$1,341,440
	2020	$2,826,523	$2,826,523
	2021	$2,483,677	$2,483,677
	2022	$2,132,179	$2,132,179
	2023	$1,783,939	$1,783,939
	2024	$1,432,773	$1,432,773
	2025	$1,096,850	$1,096,850
	2026	$758,521	$893,433
	2027	$544,639	$798,702
	2028	$390,107	$702,171
	2029	$241,446	$612,621
	2030	$93,901	$521,518
	2031	$0	$436,504
	2032	$0	$350,835
	2033	$0	$264,506
	2034	$0	$177,511
	2035	$0	$89,845
	2036	$0	$1,504
	2037	$0	$0
	2038	$0	$0
	2039	$0	$0
	2040	$0	$0
Total		$15,269,679	$17,946,533

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

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.	
37	Subject: NNG Upgrade Costs Reference: Sexton Direct, Page 17 A. Please provide cost estimates for an incremental approach to expanding capacity in the Rochester Area. B. Please provide cost estimates for using looping to meet expected demand in the Rochester Area. 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).

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

MERC Response:

A. This portion of the Supplemental Response was prepared by Timothy Sexton:

As stated on lines 10-12 on Page 17 of the Direct Testimony of Timothy Sexton, MERC cannot specify exactly which expansion facilities NNG would ultimately install to support an incremental approach. Rather, any incremental facility expansion facility project and the estimated cost of such incremental expansion would be as designed by NNG based upon conditions existing at the time that each tranche of incremental expansion is initiated.

In order to develop incremental expansion projects, NNG would develop project designs based upon a myriad of factors including: (a) the quantity of capacity requested by its customers for each tranche of incremental capacity, (b) NNG facilities in service at the time that each incremental expansion is requested, and (c) capacity contracted on its system at the time each incremental expansion is requested.

As these conditions are unknown, and as design decisions would be as determined by NNG, MERC cannot develop a cost estimate associated with an incremental approach undertaken by NNG to expand capacity to the Rochester Area.

B. MERC does not have information related to NNG's costs to loop its system to meet expected demand in the Rochester Area. MERC utilized a competitive RFP process to evaluate the lowest cost alternatives to meet long term demand. NNG's response was to utilize compression to expand its mainline to meet MERC's demand requirement. As detailed in the testimony, NNG's proposal was the most cost effective alternative among the bid proposals to meet long term Rochester demand requirements.

SUPPLEMENTAL RESPONSE (June 9, 2016)

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

In informal discussions with the Department of Commerce("DOC"), MERC was requested to develop a "good faith estimate" of costs reflective of those that might have been incurred to expand NNG's system to support MERC requirements assuming that MERC had initiated a series of smaller incremental expansions to meet long term growth requirements.

As described below in this supplemental response, and based upon the assumptions and analysis described, an incremental approach to adding capacity would have added approximately $8 million net present value ("NPV") of additional costs compared to the approach taken. In light of the overall system configuration and the work that needed to be undertaken to increase capacity into the Rochester area, it would have been infeasible to avoid these excess costs, even if MERC had sought somewhat less capacity overall. Most notably, the pipeline and ancillary work on NNG's system would have been required in any reasonable scenario. Further, adding incremental compression using smaller units is likely about double the cost (on a per unit basis) of adding a single large compressor and would have resulted in substantially similar overall costs even if MERC had sought less capacity overall that required less compression.

Finally, by picking a robust capacity level, MERC achieves longer-term benefits for its customers at a reasonable cost and increases overall customer reliability without incurring excess costs. In fact, if MERC had considered a smaller phased-in approach to reduce the long-term capacity to, for example, 30,000 Dth/day, it would have resulted in a project that was actually slightly more expensive, than the chosen 45,000 Dth/day increase. In other words, stopping at 30,000 Dth/day would have cost more and resulted in less benefits to MERC's customers.

Phased In Approach Based Upon NNG Alternative Bid Proposals

In addition to its bid proposals to provide 45,000 Dth/day in one tranche as requested in MERC's RFP, NNG also provided MERC with bid proposals designed to provide MERC with an incremental Phased Approach adding the requested capacity in multiple tranches over time.

A review of the bid proposals provided by NNG led MERC to conclude that, in addition to providing enhanced capacity rights versus the Phased proposals, the Upfront proposals provided superior economic results for MERC and its customers.

As an example, within its Supplemental Proposal dated February 18, 2015, NNG provided an "Upfront Proposal 4.0" which provided 45,000 Dth/day of incremental delivery capacity to MERC at Rochester, which when combined with MERC's existing delivery capacity to

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

Rochester provided for a total delivery capacity of 100,169 Dth/day at the initiation of the project. In addition, within this same Supplemental Proposal, NNG also provided a "Phased Proposal 4.2" which provided 17,500 Dth/day of incremental capacity in the first year of the project and 27,500 Dth/day of incremental capacity in the year 2022. Each of these two proposals contained fixed transportation service rates providing MERC and its customers with rate certainty for the capacity segments.

Based upon rates quoted by NNG, the Phased Proposal 4.2 ultimately led to a higher NPV of service costs over the contract term than did the Upfront Proposal 4.0. The attached ***Highly Sensitive Trade Secret Attachment_1_DOC_37_Supplement*** provides a comparison of these costs associated with each proposal. The Highly Sensitive Trade Secret Version of Attachment_1_DOC_37_Supplement is designated as a Highly-Sensitive Trade Secret in its entirety. This information includes third-party confidential information and MERC's competitors and suppliers could gain competitive advantage if this information were publicly available. This attachment shall be treated in accordance with the Highly-Sensitive Trade Secret Protective Order dated April 14, 2016.

Based upon the facts that: (a) the Phased In Proposal 4.2 ultimately led to higher costs for MERC and its customers than the Upfront Proposal 4.0; and (b) the Phased in Proposal 4.2 provided lower capacity quantities during the initial years of the project term, overall the Phased Proposal 4.2 was not competitive with the Upfront Proposal 4.0.

Pipeline Looping versus Mainline Compression

Within both of the aforementioned proposals from NNG, Phased Proposal 4.2 and Upfront Proposal 4.0, NNG designed facilities such that mainline capacity expansions were provided via the installation of incremental compression. In order to explore alternatives, NNG also reviewed the potential to expand its system using pipeline loops of its mainline rather than compression additions.

Specifically, NNG provided a Phased Proposal 4.1 that included pipeline loops as a means to expand its mainline. However Phased Proposal 4.1, which provided the same physical expansion capacity in each of the two phases of the project as provided by each of the two phases of Phased Proposal 4.2, resulted in a capital cost that was 15-20% higher than Phased Proposal 4.2.

This result, with the compression based Proposal 4.2 having a lower capital requirement than the pipeline based Proposal 4.1, is consistent with general industry trends as the cost

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

of adding compression is generally a lower cost option than adding loop with pipeline loop added only after the ability to expand via compression is exhausted.

As an aside, I did not include Phased Proposal 4.1 in the comparative analysis versus the alternative Upfront Proposal 4.0 and Phased Proposal 4.2 for two reasons. First, based upon a comparison of capital requirements, Phased Proposal 4.1 was clearly an inferior option versus Phased Proposal 4.2 so the comparison is largely unnecessary. Second, unlike Phased Proposal 4.2, NNG did not quote a fixed rate for the second phase of Phased Proposal 4.1. Rather, NNG simply stated that the rate applicable to the second phase of the project would be based upon a calculated Discounted Capital Recovery Rate to be determined based upon actual installation costs at the time the project was initiated. Thus, in addition to being more expensive, this alternative would have exposed MERC to an uncapped exposure moving forward.

Incremental Expansions to Achieve Added 45,000 Dth/day of Capacity

This section of the Supplemental Response provides a "good faith estimate" of costs that would reasonably be expected to be incurred to initiate a series of small scale capacity expansions to meet MERC's long term capacity requirements at Rochester.

As mentioned in its initial response to DOC IR-37, MERC cannot say with certainty what facilities would have been installed by NNG utilizing an incremental approach due to the facts that:

- facility selection and optimization are developed by NNG at its sole discretion at the time that each incremental expansion is initiated;
- required facilities for each incremental expansion would be dependent upon the facilities that NNG had in operation and contractual obligations that NNG had in place at the time of any requested incremental expansion; and
- required facilities for each incremental expansion would be subject to regulatory processes including FERC open season requirements, which could lead to demand requirements in excess of MERC's then current incremental requirement.

Nevertheless, based upon a general knowledge of the system and an understanding of the types of upgrades required to support an incremental approach, we have reviewed potential facility requirements and facility costs to develop a good faith estimate of potential costs associated with an incremental expansion approach.

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

In preparing this good faith estimate, simplifying assumptions were made to aid in development of the estimate and comparisons:

- This analysis assumes that NNG's facilities and contractual obligations remain static during the period of the incremental expansions. It is important to recognize that this assumption may not be true in practice and, in fact, it is likely that third party customers will acquire expansion capacity on NNG's mainline between the proposed incremental expansions undertaken by MERC. As a result, the lowest cost incremental expansion opportunities may not be available at the time each increment is requested by MERC and, as a result, incremental project expansion costs would be even higher than depicted herein.
- Using an incremental approach could, in fact, expose MERC to the risk of changing contractual terms. As noted in the Direct Testimony of Timothy Sexton, MERC negotiated significant advantageous terms in its Precedent Agreement with NNG, terms which may or may not have been available using an incremental approach.
- Further, in order to ensure a consistent platform for expansions, the facilities included within NNG's proposal 4.3 have been utilized as a comparison versus potential incremental facilities

Utilizing this approach, the following describes the process utilized to develop a good faith estimate of long term costs required to develop an incremental phased-in expansion approach to support MERC's long term growth requirements. The following provides a detailed discussion of the assumptions utilized to develop the good faith estimate and the attached ***Highly Sensitive Trade Secret Attachment_2_DOC_37_Supplement*** compares the long term costs of the good faith estimate of an incremental approach versus the selected transaction. The Highly Sensitive Trade Secret Version of Attachment_2_DOC_37_Supplement is designated as a Highly-Sensitive Trade Secret in its entirety. This information includes third-party confidential information and MERC's competitors and suppliers could gain competitive advantage if this information were publicly available. This attachment shall be treated in accordance with the Highly-Sensitive Trade Secret Protective Order dated April 14, 2016.

As illustrated in Attachment 2, the evaluation indicates that the incremental approach to develop the same 45,000 Dth/day of capacity provided by the project using an incremental

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

approach would have resulted in an approximate $8 million increase in the NPV of costs to MERC and its customers versus the selected transaction.

Further, using the same incremental approach, and limiting expansion capacity to 30,000 Dth/day would have resulted in a project with an NPV of costs that are about $1 million higher than the proposed project with 45,000 Dth/day of upfront capacity.

Required Facilities:

The Facilities that NNG has advised will be required to effectuate the service under its Proposal 4.2 include: (i) the installation of 15,000 HP of compression along NNG's mainline; (ii) the installation of a new delivery lateral from NNG's La Crosse Branchline to the proposed new MERC Rochester station; and (iii) various ancillary metering and pipeline facilities.

Although each facility is described in more detail below, it is worth noting that not all of the proposed facilities can be staged in using an incremental approach. For example, a large part of the cost is associated with a new 12 mile delivery lateral. With respect to this delivery lateral, there is no viable method to stage in costs. Either the lateral is built or it is not. If only a portion of the lateral were built, then the lateral could not operate as it would not extend all the way to the market. In fact, the bulk of NNG's proposed facilities, delivery lateral, meter/regulator installations, etc., are not generally scalable and are either installed or not installed.

In contrast, NNG's largest cost item, the 15,000 HP mainline compressor unit, is potentially scalable with the possibility that smaller units are installed over time. Thus, within the development of the Good Faith Estimate, it is assumed that the compressor is staged in over time.

Finally, with respect to the mainline compressor installations, an alternative would be to install segments of pipeline loop rather than add mainline compression. However, as noted above and as a general rule of thumb, to the extent expansions can be facilitated via compression rather than pipeline loop, capital costs are minimized with compression installations. As such, we have focused our evaluation on increasing mainline capacity via compressor installations rather than pipeline loop based expansion.

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

The following describes how each of these facility installations are treated within the development of the good faith estimate of facility costs associated with the incremental approach.

Mainline Compression:

In order to develop a good faith estimate of required compression additions in the evaluation of incremental facilities, it is assumed that the ratio remains constant that NNG can expand capacity by 4,500 Dth/day for each 1,500 HP installed (consistent with proposed project expansion of 45,000 Dth/day of capacity based upon a single 15,000 HP installation).

Based upon this ratio, in order to meet the projects initial delivery obligation of 10,500 Dth/day to MERC during the 2018-19 winter at Rochester, NNG would install 3,500 HP of mainline compression in 2018-19.

Next, within the long term good faith estimate, this incremental approach is continued with an additional 1,500 HP of compression (and an associated 4,500 Dth/day of capacity) added during each year in which growth would otherwise have reduced available capacity reserve to 5% or less.

Lateral Line from La Crosse Branch Line to New Rochester Gate Station

Within the underlying transaction that is the subject of this proceeding, NNG has advised that in order to meet MERC's delivery quantity and pressure requirements, NNG will need to install a new lateral line from its La Crosse branch line to MERC's proposed new Rochester gate station. In the agreed transaction, NNG was to support delivery of the initial 10,500 Dth/day of incremental delivery quantities absent this lateral with the lateral required for growth commencing in the 2019-20 winter and beyond.

With respect to an incremental approach related to the lateral line, a lateral cannot be installed in segments as the entirety of the line must be constructed from the proposed receipt point at the La Crosse branch line to the proposed delivery point at the new Rochester Gate Station in order to provide service. In other words, this lateral is necessary in its entirety to support capacity additions into Rochester regardless whether the selected

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

approach or the incremental approach is used. As a result, the cost of this part of the work must be incurred in any event.

Recognizing that the line must be installed as a single facility, and that the facility is required to support demand growth in 2019-20, it is assumed that the entirety of the lateral as well as the "new unregulated delivery station" to the new Rochester gate station is installed in the year 2019-20 to support the incremental project scenario.

Other Ancillary Facilities:

The remaining facilities described by NNG to support the project include facilities associated with the initial year 1 expansion growth and facilities that could potentially be delayed with an incremental approach. A description of these facilities and treatment in the incremental approach are as follows:

Year 1 Facilities:

Facilities that NNG has stated are required to support Phase 1 growth requirements include the installation of an "MAOP regulator" on the Rochester 1D branch line and installation of a "Branch Line Master Meter" on the Rochester 1D branch line. As these facilities are required to support initial deliveries, it is assumed in the good faith estimate that these facilities must be installed in the first year of the project term whether the selected approach or the incremental approach is considered.

Later Facilities:

Finally, NNG has included facilities to (a) Uprate 8 miles of its La Crosse branch line; and (b) Modify the La Crosse branch line take off setting. As it is unclear when these uprate facilities are to be installed, it is assumed in the good faith estimate that costs associated with these facilities are staged in with demand growth.

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

Facility Installation Costs in Good Faith Estimate of Incremental Expansion Facilities

NNG has advised that the overall cost of its work is in the $55-60 million range. It is comprised of: (i) the proposed 15,000 HP of mainline compression with a cost of approximately $30 million, (ii) the new lateral and delivery meter with an approximate cost of $22.3 million, (iii) the Year 1 ancillary facilities with an approximate cost of $1.4 million; and (iv) the later ancillary facilities with an approximate cost of $2.1 million.

With respect to the compressor installations, as discussed on pages 24 and 25 of MERC Witness Sexton's Direct Testimony, economies of scale are illustrated in a comparison of NNG's West Leg 2014 project versus NNG's proposed project to serve the Rochester demand. In the West Leg 2014 project, NNG is installing 4,700 HP of compression at its proposed Fremont Compressor station at a unit cost of approximately $3,800 per HP installed.[1] Conversely, in the Rochester project, NNG is installing 15,000 HP at a unit cost of approximately $2,000 per HP installed.

The scope of the 4,700 HP of compression being installed in NNG's West Leg 2014 project is consistent with the scope of the projected 2018-19 HP installation of 4,500 HP utilized in the incremental approach analysis. As such, it is reasonable to utilize the $3,800 / HP unit cost to develop a good faith estimate of this installation. Further, while it is likely that the West Leg 2014 project, at an installed HP of 4,700 HP would enjoy economies of scale versus incremental compression installations of only 1,500 HP supporting the incremental Rochester project alternative, for ease and simplicity, we have assumed that the proposed 1,500 HP of incremental compression needed in each incremental capacity tranche is installed at the West Leg unit cost of $3,800 per HP. Although this assumption has been included, it is worth noting that this is a conservative assumption and in reality, costs for the 1,500 HP compressor increments would likely be higher than the 4,700 HP West Leg installation due to economies of scale and inefficiencies associated with multiple mobilization / demobilization efforts.

[1] Within Exhibit K to NNG's West Leg FERC Certificate Application Filing (FERC Docket No. CP13-528), NNG included a cost estimate of $18,015,126 associated with the installation of 4,700 HP of compression which calculated to an average unit cost slightly higher than $3,800 per HP installed.

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

With respect to the remaining facilities, as it is assumed that these facilities are staged in based upon demand growth requirements. NNG's cost estimates have been utilized with costs displaced to later years when possible.

Construction Cost Escalator, Discount Rate, and Results

In order to recognize the impacts of inflation on construction costs over time, annual construction costs have been escalated at an inflation rate of 2.5% per year during the long term project life.

Next, the net present value of facility installations utilizing the incremental approach have been discounted back to present conditions utilizing a 7.3048% discount rate which corresponds to the Commission Authorized Rate Case Rate of Return illustrated in Appendix D to MERC's Petition filing in this proceeding.

As noted above, and as illustrated in ***Highly Sensitive Trade Secret Attachment_2_DOC_37_Supplement, Page 1 of 2***, the resulting net present value of costs that would be incurred by MERC and its customers utilizing the incremental approach is approximately $8 million greater than those that are incurred utilizing NNG's Proposal 4.3 alternative.

Incremental Expansions to Achieve Only 30,000 Dth/day of Incremental Capacity

Finally, in order to evaluate the acquisition of an ultimately smaller capacity quantity for MERC, we have also developed a good faith estimate of incremental facility costs assuming that MERC were to stop acquiring incremental capacity after an additional 30,000 Dth/day of incremental capacity were obtained. MERC chose the larger 45,000 Dth/day level in order to provide customers with long-term reliability and to ensure that the system would have adequate capacity to serve expanding customer needs into the foreseeable future.

This scenario is included on ***Highly Sensitive Trade Secret Attachment_ 2_DOC_37_Supplement, Page 2 of 2***. As illustrated, even if incremental expansions are stopped at 30,000 Dth/day, the NPV of overall costs would still remain approximately $1 million higher than the acquisition of 45,000 Dth/day of capacity from NNG as included within the filed project.

In other words, using a phased-in approach, the lower capacity would have resulted in greater costs and would have provided fewer long-term reliability benefits to customers.

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

Additional Comparisons:

This portion of the response was prepared by Lindsay Lyle:

In addition, DOC Staff informally requested that MERC provide a cost analysis and breakdown of other projects undertaken by MERC and by its affiliates in the larger holding company system. In response to this request, MERC provides cost data pertaining to the current Rochester Project Phase II being undertaken by MERC, to allow comparison of those data with:

1. the Rochester Project Phase I, addition of new 12" pipe undertaken by MERC in 2015;
2. the Cloquet 12 inch pipe installation undertaken by MERC in 2006 and 2008;
3. the Guardian II transmission and regulator station projects from 2006-07 undertaken on behalf of MERC's affiliate Wisconsin Public Service;
4. the Monroe, MI project from 2012-13 undertaken by MERC's affiliate Michigan Gas Utilities ("MGU");
5. the Wausau (Mosinee) New Gate Station project from 2014 undertaken by MERC's Affiliate Wisconsin Public Service; and
6. the Manlove Field Transmission project from 2016 in Illinois undertaken by MERC's affiliate Peoples Gas.

Each of these projects included the design, development, and construction of natural gas infrastructure on the regional system. MERC provides available data for these projects in categories of materials, internal labor, contracted services, land acquisition, and other costs and provides data points on total cost and a calculated cost per mile for the project. *Attachment_3_DOC_37_Supplement_*Nonpublic provides this information. The Nonpublic version of Attachment 3 contains trade secret data as defined by Minn. Stat. 216B.37(1)(b), including confidential contractor pricing information that is not generally known to and not readily ascertainable by vendors and competitors of MERC who could obtain financial advantage from its use.

MERC notes that the design and cost of natural gas infrastructure projects can vary widely depending upon a variety of factors, including (i) the type of project being deployed (transmission versus gate station), (ii) topography and other environmental factors of the construction area, (iii) zoning and local land use, (iv) location and characteristics of other related infrastructure, (v) timing, and a variety of other factors. In addition, costs can vary

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

PUBLIC DOCUMENT – HIGHLY SENSITIVE TRADE SECRET INFORMATION HAS BEEN EXCISED PER HSTS ORDER IN DOCKET NO. G011/M-15-895

HIGHLY SENSITIVE TRADE SECRET INFORMATION TO BE FILED ONLY IN DOCKET NO. G-011/M-16-315

widely depending upon permitting requirements and restrictions. Whether state permitting is required for any particular project is an important factor that can result in increased costs, depending upon the route selected, changes to the scope and restrictions and requirements included in the permit. Another example of how costs vary relates to the schedule for installation. If a project must be installed over multiple construction cycles (as is the case for Phase II of the Rochester Project) additional costs are incurred relating to mobilization and demobilization of work.

As a result these and other factors, total cost of a project or even a per-mile extrapolation may be interesting data points. However, drawing conclusions from such data points from one project to another may not reflect a valid comparison with Phase II of the Rochester Project and can be misleading.

Response by:	Timothy Sexton (Incremental Approach)	Response by: Lindsay K. Lyle (Other Projects)
Title:	Consultant	Engineering Manager
Department:	Gas Supply Consulting	Minnesota Energy Resources Corporation
Telephone:	(281) 558-0735 (Ext.2)	(651) 322-8909

Heinen, Adam (COMM)

From: Lee, Amber S <ASLee@minnesotaenergyresources.com>
Sent: Friday, June 17, 2016 11:35 AM
To: Heinen, Adam (COMM)
Cc: Ansay, Michael J
Subject: FW: Voice Mail from Adam Heinen (45 seconds)
Attachments: (651) 539-1825 (45 seconds) Voice Mail.mp3

Hold the horses, Mike and I were way off on this one, sorry Adam. We checked with Sarah and this is what we learned: On average MERC has utilized half of the Bison capacity from Jan 2011 to Nov 2015. We have no supply contracts in place as of Dec 2015. And we've not been able to release the capacity – no takers.

Sorry for the confusion. Let me know if you want to discuss.

Have a good weekend!

Amber

From: Lee, Amber S
Sent: Wednesday, June 15, 2016 3:45 PM
To: Adam.Heinen@state.mn.us
Cc: Ansay, Michael J
Subject: FW: Voice Mail from Adam Heinen (45 seconds)

Hey Adam. I talked to Mike Ansay about this. We don't think we've ever flowed gas via the Bison Pipeline. But we have used the associated Northern Border Pipeline contract to deliver gas on a sporadic basis in the past. Recently, over the past three or so months, the NBPL capacity has been used to gain access to low cost Canadian gas or it has been released to third parties resulting in capacity release credits.

Please let us know if you need more info.

Thanks!

Amber

Amber S. Lee
Regulatory and Legislative Affairs Manager
Minnesota Energy Resources Corporation
2665 145th Street West
Rosemount, MN 55068
Office: 651-322-8965
Cell: 651-278-6165

From: Microsoft Outlook
Sent: Wednesday, June 15, 2016 11:52 AM
To: Lee, Amber S
Subject: Voice Mail from Adam Heinen (45 seconds)

You received a voice mail from Adam Heinen at (651) 539-1825

Caller-Id: (651) 539-1825

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.	
36	Subject: NNG Capacity Costs Reference: Lee Direct, Page 33, Lines 1-6 Please compare the expected costs in the above reference to the costs associated with MERC's current Bison Pipeline contract. 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:** Page 1 of Attachment_DOC_36.xlsx calculates the cost impact per average Residential, Small C&I, and Large C&I customers for the NNG capacity costs related to the Rochester expansion project. As discussed in the above referenced cite the average Residential customer impact would be \$2.81 in 2018 up to \$32.16 in 2020 for the NNG capacity increase associated with the Rochester expansion. Page 2 of Attachment_DOC_36.xlsx calculates the cost impact per average Residential, Small C&I, and Large C&I customers of the Bison capacity costs. The average Residential customer impact in 2017 is \$38.09, and the capacity contract ends May 22, 2018.

Response by: Amber Lee

Title: Regulatory and Leg. Affairs Mgr.

Department: Regulatory Affairs

Telephone: (651) 322-8965

List sources of information:

MERC included the Albert Lea PGA volumes in this cost comparison under the assumption that the Albert Lea and NNG PGAs will be consolidated before the Rochester Project costs are allocated.

Response by: Amber Lee

Title: Regulatory and Leg. Affairs Mgr.

Department: Regulatory Affairs

Telephone: (651) 322-8965

List sources of information:

216B.1638 RECOVERY OF NATURAL GAS EXTENSION PROJECT COSTS.

Subdivision 1. **Definitions.** (a) For the purposes of this section, the terms defined in this subdivision have the meanings given them.

(b) "Contribution in aid of construction" means a monetary contribution, paid by a developer or local unit of government to a utility providing natural gas service to a community receiving that service as the result of a natural gas extension project, that reduces or offsets the difference between the total revenue requirement of the project and the revenue generated from the customers served by the project.

(c) "Developer" means a developer of the project or a person that owns or will own the property served by the project.

(d) "Local unit of government" means a city, county, township, commission, district, authority, or other political subdivision or instrumentality of this state.

(e) "Natural gas extension project" or "project" means the construction of new infrastructure or upgrades to existing natural gas facilities necessary to serve currently unserved or inadequately served areas.

(f) "Revenue deficiency" means the deficiency in funds that results when projected revenues from customers receiving natural gas service as the result of a natural gas extension project, plus any contributions in aid of construction paid by these customers, fall short of the total revenue requirement of the natural gas extension project.

(g) "Total revenue requirement" means the total cost of extending and maintaining natural gas service to a currently unserved or inadequately served area.

(h) "Transport customer" means a customer for whom a natural gas utility transports gas the customer has purchased from another natural gas supplier.

(i) "Unserved or inadequately served area" means an area in this state lacking adequate natural gas pipeline infrastructure to meet the demand of existing or potential end-use customers.

Subd. 2. **Filing.** (a) A public utility may petition the commission outside of a general rate case for a rider that shall include all of the utility's customers, including transport customers, to recover the revenue deficiency from a natural gas extension project.

(b) The petition shall include:

(1) a description of the natural gas extension project, including the number and location of new customers to be served and the distance over which natural gas will be distributed to serve the unserved or inadequately served area;

(2) the project's construction schedule;

(3) the proposed project budget;

(4) the amount of any contributions in aid of construction;

(5) a description of efforts made by the public utility to offset the revenue deficiency through contributions in aid to construction;

(6) the amount of the revenue deficiency, and how recovery of the revenue deficiency will be allocated among industrial, commercial, residential, and transport customers;

(7) the proposed method to be used to recover the revenue deficiency from each customer class, such as a flat fee, a volumetric charge, or another form of recovery;

(8) the proposed termination date of the rider to recover the revenue deficiency; and

(9) a description of benefits to the public utility's existing natural gas customers that will accrue from the natural gas extension project.

Subd. 3. **Review; approval.** (a) The commission shall allow opportunity for comment on the petition.

(b) The commission shall approve a public utility's petition for a rider to recover the costs of a natural gas extension project if it determines that:

(1) the project is designed to extend natural gas service to an unserved or inadequately served area; and

(2) project costs are reasonable and prudently incurred.

(c) The commission must not approve a rider under this section that allows a utility to recover more than 33 percent of the costs of a natural gas extension project.

(d) The revenue deficiency from a natural gas extension project recoverable through a rider under this section must include the currently authorized rate of return, incremental income taxes, incremental property taxes, incremental depreciation expenses, and any incremental operation and maintenance costs.

Subd. 4. **Commission authority; order.** The commission may issue orders necessary to implement and administer this section.

Subd. 5. **Implementation.** Nothing in this section commits a public utility to implement a project approved by the commission. The public utility seeking to provide natural gas service shall notify the commission whether it intends to proceed with the project as approved by the commission.

Subd. 6. **Evaluation and report.** By January 15, 2017, and every three years thereafter, the commission shall report to the chairs and ranking minority members of the senate and house of representatives committees having jurisdiction over energy policy:

(1) the number of public utilities and projects proposed and approved under this section;

(2) the total cost of each project;

(3) rate impacts of the cost recovery mechanism; and

(4) an assessment of the effectiveness of the cost recovery mechanism in realizing increased natural gas service to unserved or inadequately served areas from natural gas extension projects.

History: *1Sp2015 c 1 art 3 s 20*

PUBLIC DOCUMENT— TRADE SECRET DATA HAS BEEN EXCISED

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.	
26	Subject: Capacity Release

Reference: Mead Direct, Page 28, Line 14 through Page 29, Line 8

A. Please provide a list of each individual capacity release MERC has executed on its system, on a monthly basis, since January 2007. Please also include the amount of volumes released and the amount of revenues associated with these capacity releases.

B. Please fully explain whether MERC has considered, or will consider, long-term capacity release for any excess capacity.

C. Please fully explain whether the Precedent Agreement allows long-term capacity release and, if so, is it limited to a geographic area or can MERC sell it anywhere on the NNG system.

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).

Response by: Sarah R. Mead

Title: Manager of Gas Supply

Department: Gas Supply

Telephone: 920-433-7647

List sources of information:

PUBLIC DOCUMENT— TRADE SECRET DATA HAS BEEN EXCISED

MERC Response:

A. Please see attached file: IR 26a G011-M-15-895 Capacity Release Data NNG_NONPUBLIC.xls. Individual capacity release transaction data is unavailable for January through June, 2007. However, monthly volume and revenue data is provided for that time period. This attachment is nonpublic in its entirety as contains information not generally known or readily ascertainable by competitors and suppliers of MERC who could obtain economic advantage from its disclosure.

B. Yes, MERC will consider more than a month (long term) capacity release for underutilized capacity. MERC will evaluate this type of release on a case by case basis.

C. MERC may release the Rochester Capacity and the Southeastern Minnesota on a temporary (either short or long-term) and permanent basis, however, there are some cost considerations to take into account.

- Rochester: The Rochester capacity is subject to the discount limitations (usage at primary deliveries only with 20% alternates) and could cause MERC to infringe and be subject to the penalties. In addition, if MERC or the acquiring shipper realigns the capacity away from Rochester MERC would have to pay back the remaining Rochester obligation and the capacity would go to tariff rates for the remainder of the term.

- Southeastern Minnesota: The Southeastern Minnesota capacity is tariff rate capacity and can be used at alternate receipts and deliveries without penalty. Similar to the Rochester Entitlement, if MERC or an acquiring shipper realigns the capacity away from Southeastern Minnesota points MERC would have to pay back the remaining Southeastern Minnesota obligation and the capacity would remain at tariff rates for the remainder of the term. The underlying capacity at the Southeastern Minnesota Points may be realigned without penalty.

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

PUBLIC DOCUMENT—TRADE SECRET DATA HAS BEEN EXCISED

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.	
32	Subject: Interruptible Customers

Reference: Lee Direct, Page 28, Lines 11-12

Please list any, and all, requests by interruptible customers for transition to firm service. As part of this response, please also provide average sales for each of these customers and which Town Border Station serves each customer.

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 Attachment_DOC_32_NONPUBLIC. This attachment shows customers in the Rochester area who have transitioned from interruptible to firm service over the past five years.

Over the past five years, MERC has not denied any request from any non-firm customer to

Response by: Amber Lee

Title: Regulatory and Leg. Affairs Mgr.

Department: Regulatory Affairs

Telephone: (651) 322-8965

List sources of information:

PUBLIC DOCUMENT—TRADE SECRET DATA HAS BEEN EXCISED

become a firm customer or transition some non-firm load to firm. In some instances, however, customers declined to pursue the transition to firm load because the cost of the Contribution in Aid of Construction ("CIAC") was too high. This is especially true in situations that required additional transmission capacity on the NNG pipeline.

The nonpublic version of this response contains customer usage information defined as trade secret by Minn. Stat. §13.37, subd. 1(b). This information 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 Lee

Title: Regulatory and Leg. Affairs Mgr.

Department: Regulatory Affairs

Telephone: (651) 322-8965

List sources of information:

Docket No. G011/M-15-895
DOC Ex. ____ AJH-25 (Heinen Direct)
Page 1 of 3

http://www.postbulletin.com/news/local/rpu-chooses-boldt-to-build-new-million-plant/article_1f6c9fba-5d08-5944-b300-47299c9d3052.html

RPU chooses Boldt to build new $62 million plant

Jeff Kiger, jkiger@postbulletin.com Feb 24, 2016

Ken Klotzbach

Buy Now

Wally Schlink, SMMPA Alternate Representative & Director of Power Resources at RPU

The Rochester Public Utility Board flipped the switch Tuesday to fire up the construction of a new peaking power plant in the northwest quadrant.

The board chose Boldt Co.'s $32.2 million bid to engineer and build the new plant to be called Westside Energy Station.

Wisconsin-based Boldt, working with Sargent & Lundy, was selected as the top bidder. The peaking power plant is slated to be built at 5846 19th St. NW.

Wally Schlink, RPU's director of power resources, said the "aggressive schedule" calls for the new plant to be operational by May 1, 2018.

Factoring the rest of the costs for the Westside Energy Station, Schlink told the board the total cost should be $62.6 million. That's below the estimated $75 million budgeted for the project.

The board previously approved buying five reciprocating engine generators from the U.S. arm of the Finland-based Wartsila for $22.5 million. The engines run on natural gas.

Boldt, which has had a large office in Rochester since 2008, beat out four other bidders for the contract. Boldt's proposal breaks down as $3,798,289 as "a firm price" for engineering and

construction management, $28,437,922 for the balance of the project and $6,447,242 for

contingency to cover variables such as material costs or changes.

Boldt formed a team with power plant experts Sargent & Lundy of Chicago to bid the project as the Westside Energy Partners.

Of the bidders that RPU staff deemed suited to handle the project, the other top competitor for the bid was Burns & McDonnell of Kansas City, Mo. Burns & McDonnell did the preliminary engineering study on the project for RPU.

Docket No. G011/M-15-895
DOC Ex. ____ AJH-25 (Heinen Direct)
Page 3 of 3

"Boldt and Burns were neck and neck," Schlink said.

In the end, the difference came down to cost. Burns bid a total of $37.2 million to build the Westside plant.

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.	
23	Subject: Capacity Costs Reference: Mead Direct, Page 12, Lines 14-18 MERC references pricing upcharges and that MERC negotiated the ability to deliver 20 percent of the Rochester volumes throughout the MERC NNG system in Minnesota. Please fully explain whether MERC is able to deliver additional volumes subject to a pricing upcharge. If so, please also fully explain and quantify the amount of these potential upcharges. 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 Precedent Agreement with NNG has capped the capacity costs at the current max tariff rates. Tariff rates are impacted by items such as NGA Section 4 or Section 5 general rate proceeding, company specific asset tracking mechanism, or pretrial settlement. If NNG's rates were to increase in the future, MERC will not pay that upcharge for the deliveries up to the 20% to alternative areas within NNG, however if it delivered more than the 20% to an

Response by: Sarah R. Mead

Title: Manager of Gas Supply

Department: Gas Supply

Telephone: 920-433-7647

List sources of information:

alternative area it would be a the max rates posted in the tariff. For example in 2020, if NNG had a rate case and the rates increased by 10 cents, MERC would not pay that 10 cents additional on any of the capacity scheduled to Rochester or 20% scheduled elsewhere. However, if MERC scheduled 30% to an alternative area the 10% difference would have an upcharge of 10 cents.

Response by: Sarah R. Mead

Title: Manager of Gas Supply

Department: Gas Supply

Telephone: 920-433-7647

List sources of information:

Northern States Power Company

Capital Expenditure (CWIP Only) - Actual and Forecast Through 2020
NSPM Gas
($s)

		Actual		Mix	Forecast					
ref	Project Name	2013	2014	2015	2016	2017	2018	2019	2020	Total
a	GUIC Projects	10,317,189	12,204,219	30,753,498	31,254,146	23,644,846	44,863,246	49,992,300	48,185,400	251,214,844
b	All Other Projects	43,682,722	54,473,478	52,342,595	52,413,057	48,821,965	48,784,002	49,333,327	50,950,671	400,801,817
	Total: NSPM Gas Projects	53,999,911	66,677,697	83,096,093	83,667,203	72,466,811	93,647,248	99,325,627	99,136,071	652,016,661
c	Internal Labor (GUIC Projects)	411,673	336,205	994,355	-	-	-	-	-	1,742,234
= a - c	Total for GUIC Recovery*	9,905,516	11,868,014	29,759,143	31,254,146	23,644,846	44,863,246	49,992,300	48,185,400	249,472,610

*ties to Schedule C excluding pre-2013 expenditures

DESTINATION MEDICAL CENTER

469.40 DEFINITIONS.

Subdivision 1.Application.

For the purposes of sections 469.40 to 469.47, the terms defined in this section have the meanings given them.

Subd. 2.City.

"City" means the city of Rochester.

Subd. 3.County.

"County" means Olmsted County.

Subd. 4.Destination Medical Center Corporation, corporation, DMCC.

"Destination Medical Center Corporation," "corporation," or "DMCC" means the nonprofit corporation created by the city as provided in section 469.41, and organized under chapter 317A.

Subd. 5.Destination medical center development district.

"Destination medical center development district" or "development district" means a geographic area in the city identified in the DMCC development plan in which public infrastructure projects are implemented.

Subd. 6.Development plan.

"Development plan" means the plan adopted by the DMCC under section 469.43.

Subd. 7.Financial interest.

"Financial interest" means a person's direct or indirect ownership or investment interest or compensation arrangement, whether through business, investment, or family, including spouse, children and stepchildren, and other relatives living with the person, as follows:

(1) ownership or investment interest in the development, acquisition, or construction of a project in the development district;

(2) compensation arrangement with respect to the development, acquisition, or construction of a project in the development district; or

(3) potential ownership or investment interest in, or compensation arrangement with respect to, the development, acquisition, or construction of a project in the development district.

Subd. 8.Medical business entity.

"Medical business entity" means a medical business entity with its principal place of business in the city that, as of June 22, 2013, together with all business entities of which it is the sole member or sole shareholder, collectively employs more than 30,000 persons in the state.

Subd. 9.Nonprofit economic development agency, agency.

"Nonprofit economic development agency" or "agency" means the nonprofit agency required under section 469.43 to provide experience and expertise to the DMCC for purposes of developing and marketing the destination medical center.

Subd. 10.Project.

"Project" means a project to implement the development plan, whether public or private.

Subd. 11.Public infrastructure project.

(a) "Public infrastructure project" means a project financed in part or in whole with public money in order to support the medical business entity's development plans, as identified in the DMCC development plan. A public infrastructure project may:

(1) acquire real property and other assets associated with the real property;

(2) demolish, repair, or rehabilitate buildings;

(3) remediate land and buildings as required to prepare the property for acquisition or development;

(4) install, construct, or reconstruct elements of public infrastructure required to support the overall development of the destination medical center development district including, but not limited to, streets, roadways, utilities systems and related facilities, utility relocations and replacements, network and communication systems, streetscape improvements, drainage systems, sewer and water systems, subgrade structures and associated improvements,

landscaping, façade construction and restoration, wayfinding and signage, and other components of community infrastructure;

(5) acquire, construct or reconstruct, and equip parking facilities and other facilities to encourage intermodal transportation and public transit;

(6) install, construct or reconstruct, furnish, and equip parks, cultural, and recreational facilities, facilities to promote tourism and hospitality, conferencing and conventions, and broadcast and related multimedia infrastructure;

(7) make related site improvements including, without limitation, excavation, earth retention, soil stabilization and correction, and site improvements to support the destination medical center development district;

(8) prepare land for private development and to sell or lease land;

(9) provide costs of relocation benefits to occupants of acquired properties; and

(10) construct and equip all or a portion of one or more suitable structures on land owned by the city for sale or lease to private development; provided, however, that the portion of any structure directly financed by the city as a public infrastructure project must not be sold or leased to a medical business entity.

(b) A public infrastructure project is not a business subsidy under section 116J.993.

(c) Public infrastructure project includes the planning, preparation, and modification of the development plan under section 469.43. The cost of that planning, preparation, and any modification is a capital cost of the public infrastructure project.

[See Note.]

Subd. 12.Year.

"Year" means a calendar year, except where otherwise provided.

History:

2013 c 143 art 10 s 3; 2015 c 1 s 6; 1Sp2015 c 1 art 8 s 1

NOTE: The amendment to subdivision 11 by Laws 2015, chapter 1, section 6, as amended by Laws 2015, First Special Session chapter 1, article 8, section 1, is effective after the governing body of the city of Rochester and its chief clerical officer timely comply with Minnesota Statutes, section 645.021, subdivisions 2 and 3, and applies retroactively to the original effective dates of the provisions of law that are amended. Laws 2015, chapter 1, section 13; Laws 2015, First Special Session chapter 1, article 8, section 1, the effective date.

469.41 DESTINATION MEDICAL CENTER CORPORATION ESTABLISHED.

Subdivision 1.DMCC created.

The city must establish a destination medical center corporation as a nonprofit corporation under chapter 317A to provide the city with expertise in preparing and implementing the development plan to establish the city as a destination medical center. Except as provided in sections 469.40 to 469.47, the nonprofit corporation is not subject to laws governing the city.

Subd. 2.Membership; quorum.

(a) The corporation's governing board consists of eight members appointed as follows:

(1) the mayor of the city, or the mayor's designee, subject to approval by the city council;

(2) the city council president, or the city council president's designee, subject to approval by the city council;

(3) the chair or a member of the county board, appointed by the county board;

(4) a representative of the medical business entity, appointed by and serving at the pleasure of the medical business entity; and

(5) four members appointed by the governor, subject to confirmation by the senate.

(b) Appointing authorities must make their respective appointments as soon as practicable after June 22, 2013, but no later than July 22, 2013.

(c) A quorum of the board is six members.

Subd. 3.Terms.

(a) A member first appointed after June 22, 2013, under subdivision 2, paragraph (a), clauses (1), (2), and (3), serves for a term coterminous with the term of the elected office, but may be reappointed.

(b) Two members first appointed after June 22, 2013, under subdivision 2, paragraph (a), clause (5), serve from the date of appointment until the first Tuesday after the first Monday in January 2017, and two members first appointed after June 22, 2013, under subdivision 2, paragraph (a), clause (5), serve from the date of appointment until the first Tuesday after the first Monday in January 2020. Thereafter, members appointed by the governor serve six-year terms.

Subd. 4.Vacancies.

A vacancy occurs as provided in section 351.02 or upon a member's removal under subdivision 7. A vacancy on the board must be filled by the appointing authority for the balance of the term in the same manner as a regular appointment.

Subd. 5.Chair.

The board must elect a chair from among the governor's appointees. The governor must convene the first meeting within 30 days of completion of all appointments to the board.

Subd. 6.Pay.

Members must be compensated as provided in section 15.0575, subdivision 3. For the purposes of this subdivision, the member representing the medical business entity shall be treated as if an employee of a political subdivision. All money paid for compensation or reimbursement must be paid out of the corporation's budget.

Subd. 7.Removal for cause.

A member may be removed by the board for inefficiency, neglect of duty, or misconduct in office. A member may be removed only after a hearing of the board. A copy of the charges must be given to the board member at least ten days before the hearing. The board member must be given an opportunity to be heard in person or by counsel at the hearing. When written charges have been submitted against a board member, the board may temporarily suspend the member. If the board finds that those charges have not been substantiated, the board member must be immediately reinstated. If a board member is removed, a record of the proceedings, together with the charges and findings, must be filed with the office of the appointing authority.

Subd. 8.Open meeting law; data practices.

Meetings of the corporation and any committee or subcommittee of the corporation are subject to the open meeting law in chapter 13D. The corporation is a government entity for purposes of chapter 13.

Subd. 9.Conflicts of interest.

Except for the member appointed by the medical business entity, a member must not be a director, officer, or employee of the medical business entity. A member must not participate in or vote on a decision of the corporation relating to any project authorized by or under consideration by the corporation in which the member has either a direct or indirect financial interest. No member may serve as a lobbyist, as defined under section 10A.01, subdivision 21.

Subd. 10.Public official.

A member of the corporation is a public official, as defined in section 10A.01, subdivision 35.

Subd. 11.Powers.

The corporation may exercise any other powers that are granted by its articles of incorporation and bylaws to the extent that those powers are not inconsistent with the provisions of sections 469.40 to 469.47.

Subd. 12.Contract for services.

(a) The corporation may contract for the services of the nonprofit economic development agency, financial advisors, other consultants, agents, public accountants, legal counsel, and other persons needed to perform its duties and exercise its powers. The corporation may contract with the city or county to provide administrative, clerical, and accounting services to the corporation.

(b) The corporation must contract with the nonprofit agency for the services enumerated in section 469.43, subdivision 6, paragraph (a). The requirement to contract with the nonprofit agency does not limit the corporation's authority to contract with other providers for the services.

Subd. 13.DMCC approval of projects.

A project must be approved by the corporation before it is proposed to the city. The corporation must review the project proposed for consistency with the adopted development plan.

Subd. 14.Dissolution.

The city must provide for the terms for dissolution of the corporation in the articles of incorporation.

History:

2013 c 143 art 10 s 4

469.42 OFFICERS; DUTIES; ORGANIZATIONAL MATTERS.

Subdivision 1.Bylaws, rules, seal.

The corporation may adopt bylaws and rules of procedure and may adopt an official seal.

Subd. 2.Officers.

The corporation must annually elect a treasurer. The chair must appoint a secretary and assistant treasurer. The secretary and assistant treasurer need not, but may, be members of the board.

Subd. 3.Duties and powers.

The officers have the usual duties and powers of their offices. They may be given other duties and powers by the corporation. The corporation must establish and maintain a Web site.

Subd. 4.Treasurer's duties.

The treasurer:

(1) must receive and is responsible for corporation money;

(2) is responsible for the acts of the assistant treasurer;

(3) must disburse corporation money by check or electronic procedures;

(4) must keep an account of the source of all receipts, and of the nature, purpose, and authority of all disbursements; and

(5) must file the corporation's detailed financial statement with its secretary at least once a year at times set by the authority.

Subd. 5.Secretary.

The secretary must perform duties as required by the board.

Subd. 6.Assistant treasurer.

The assistant treasurer has the powers and duties of the treasurer if the treasurer is absent or disabled.

History:

2013 c 143 art 10 s 5

469.43 DEVELOPMENT PLAN.

Subdivision 1.Development plan; adoption by DMCC; notice; findings.

(a) The corporation, working with the city and the nonprofit economic development agency, must prepare and adopt a development plan. The corporation must hold a public hearing before adopting a development plan. At least 60 days before the hearing, the corporation must make copies of the proposed plan available to the public at the corporation and city offices during normal business hours, on the corporation's and city's Web site, and as otherwise determined appropriate by the corporation. At least ten days before the hearing, the corporation must publish notice of the hearing in the official newspaper of the city. The development plan may not be adopted unless the corporation finds, by resolution, that:

(1) the plan provides an outline for the development of the city as a destination medical center, and the plan is sufficiently complete, including the identification of planned and anticipated projects, to indicate its relationship to definite state and local objectives;

(2) the proposed development affords maximum opportunity, consistent with the needs of the city, county, and state, for the development of the city by private enterprise as a destination medical center;

(3) the proposed development conforms to the general plan for the development of the city and is consistent with the city comprehensive plan;

(4) the plan includes:

(i) strategic planning consistent with a destination medical center in the core areas of commercial research and technology, learning environment, hospitality and convention, sports and recreation, livable communities, including mixed-use urban development and neighborhood residential development, retail/dining/entertainment, and health and wellness;

(ii) estimates of short- and long-range fiscal and economic impacts;

(iii) a framework to identify and prioritize short- and long-term public investment and public infrastructure project development and to facilitate private investment and development, including the criteria and process for evaluating and underwriting development proposals;

(iv) land use planning;

(v) transportation and transit planning;

(vi) operational planning required to support the medical center development district; and

(vii) ongoing market research plans; and

(5) the city has approved the plan.

(b) The identification of planned and anticipated projects under paragraph (a), clause (1), must give priority to projects that will pay wages at least equal to the basic cost of living wage as calculated by the commissioner of employment and economic development for the county in which the project is located. The calculation of the basic cost of living wage must be done as provided for under section 116J.013.

Subd. 2.Development plan approval by city.

Section 15.99 does not apply to review and approval of the development plan. The city shall act on the development plan within 60 days following its submission by the corporation. The city may incorporate the development plan into the city's comprehensive plan.

Subd. 3.Subject to city requirements.

All projects are subject to the planning, zoning, sanitary, and building laws; ordinances; regulations; and land use plans that apply to the city.

Subd. 4.Modification of development plan.

The corporation may modify the development plan at any time. The corporation must update the development plan not less than every five years. A modification or update under this subdivision must be adopted by the corporation upon the notice and after the public hearing and findings required for the original adoption of the development plan, including approval by the city.

Subd. 5.Medical center development districts; creation; notice; findings.

As part of the development plan, the corporation may create and define the boundaries of medical center development districts and subdistricts at any place or places within the city. Projects may be undertaken within defined medical center development districts consistent with the development plan.

Subd. 6.Nonprofit economic development agency.

(a) The medical business entity must establish a nonprofit economic development agency organized under chapter 317A to provide experience and expertise in developing and marketing the destination medical center. The corporation must engage the agency to assist the corporation in preparing the development plan. The governing board of the agency must be comprised of members of the medical community, city, and county. The agency must collaborate with city, county, and other community representatives. The nonprofit agency must provide services to assist the corporation and city in implementing the goals, objectives, and strategies in the development plan including, but not limited to:

(1) facilitating private investment through development of a comprehensive marketing program to global interests;

(2) developing and updating the criteria for evaluating and underwriting development proposals;

(3) drafting and implementing the development plan, including soliciting and evaluating proposals for development and evaluating and making recommendations to the authority and the city regarding those proposals;

(4) providing transactional services in connection with approved projects;

(5) developing patient, visitor, and community outreach programs for a destination medical center development district;

(6) working with the corporation to acquire and facilitate the sale, lease, or other transactions involving land and real property;

(7) seeking financial support for the corporation, the city, and a project;

(8) partnering with other development agencies and organizations, the city, and the county in joint efforts to promote economic development and establish a destination medical center;

(9) supporting and administering the planning and development activities required to implement the development plan;

(10) preparing and supporting the marketing and promotion of the medical center development district;

(11) preparing and implementing a program for community and public relations in support of the medical center development district;

(12) assisting the corporation or city and others in applications for federal grants, tax credits, and other sources of funding to aid both private and public development; and

(13) making other general advisory recommendations to the corporation and the city, as requested.

(b) The nonprofit economic development agency must disclose to the city and to the corporation the existence, nature, and all material facts regarding any financial interest its employees or contractors have in any public infrastructure project submitted to the city for approval and any financial interest its employees or contractors have in the destination medical center development. "Contractors" includes affiliates of the contractors or members or shareholders with an ownership interest of more than 20 percent in the contractor.

Subd. 6a.Restriction on city funds to support nonprofit economic development agency.

The nonprofit economic development agency shall not require the city to pay any amounts to the nonprofit economic development agency that are unrelated to public infrastructure project costs.

[See Note.]

Subd. 7.Audit of nonprofit economic development agency contract.

Any contract for services between the corporation and the nonprofit economic development agency paid, in whole or in part, with public money provides the corporation, the city, and the state auditor the right to audit the books and records of the agency that are necessary to certify:

(1) the nature and extent of the services furnished pursuant to the contract; and

(2) that the payment for services and related disbursements complies with all state laws, regulations, and the terms of the contract.

Any contract for services between the corporation and the agency paid, in whole or in part, with public money must require the corporation to maintain for the life of the corporation accurate and complete books and records directly relating to the contract.

Subd. 8.Report.

By February 15 of each year, the corporation and city must jointly submit a report to the chairs and ranking minority members of the legislative committees and divisions with jurisdiction over local and state government operations, economic development, and taxes, and to the commissioners of revenue and employment and economic development, and the county. The corporation and city must also submit the report as provided in section 3.195. The report must include:

(1) the development plan and any proposed changes to the development plan;

(2) progress of projects identified in the development plan;

(3) actual costs and financing sources, including the amount paid with state aid under section 469.47, and required local contributions of projects completed in the previous two years by the corporation, city, county, and medical business entity;

(4) estimated costs and financing sources for projects to be started in the next two years by the corporation, city, county, and medical business entity; and

(5) debt service schedules for all outstanding obligations of the city for debt issued for projects identified in the plan.

History:

2013 c 143 art 10 s 6; 1Sp2015 c 1 art 8 s 2

NOTE: Subdivision 6a, as added by Laws 2015, First Special Session chapter 1, article 8, section 2, is effective the day after the governing body of the city of Rochester and its chief clerical officer comply with Minnesota Statutes, section 645.021, subdivisions 2 and 3, and applies retroactively from June 22, 2013. Laws 2015, First Special Session chapter 1, article 8, section 2, the effective date.

469.44 CITY POWERS, DUTIES; AUTHORITY TO ISSUE BONDS.

Subdivision 1.Port authority powers.

The city may exercise the powers of a port authority under sections 469.048 to 469.068 for the purposes of implementing the destination medical center development plan.

Subd. 2.Support to the corporation.

The city must provide financial and administrative support, and office and other space, to the corporation. The city may appropriate city funds to the corporation for its work.

Subd. 3.City to issue debt.

The city may issue general obligation bonds, revenue bonds, or other obligations, as it determines appropriate, to finance public infrastructure projects, as provided by chapter 475. Notwithstanding section 475.53, obligations issued under this section are not subject to the limits on net debt, regardless of their source of security or payment. Notwithstanding section 475.58 or any other law or charter provision to the contrary, issuance of obligations under the provisions of this section are not subject to approval of the electors. The city may pledge any of its revenues, including property taxes, the taxes authorized by sections 469.45 and 469.46, and state aid under section 469.47, as security for and to pay the obligations. The city must not issue obligations that are only payable from or secured by state aid under section 469.47.

Subd. 4.Local government tax base not reduced.

Nothing in sections 469.40 to 469.47 reduces the tax base or affects the taxes due and payable to the city, the county, or any school district within the boundaries of the city, including without limitation, the city's general local sales tax.

Subd. 5.Project implementation before plan adoption.

The city may exercise the powers under subdivision 3 with respect to any public infrastructure project commenced within the area that will be in the destination medical center development district after June 22, 2013, but before the development plan is adopted subject to approval by the corporation. Actions taken under this authority must be approved by the corporation to be credited against the local contribution required under section 469.47, subdivision 4, or to qualify for reimbursement of the city out of state aid paid under section 469.47, subdivision 3 or 5.

[See Note.]

Subd. 6.American made steel.

The city must require that a public infrastructure project use American steel products to the extent practicable. In determining whether it is practicable, the city may consider the exceptions to the requirement in Public Law 111-5, section 1605.

Subd. 7.City contracts; construction requirements.

For all public infrastructure projects, the city must make every effort to hire and cause the construction manager and any subcontractors to employ women and members of minority communities. Goals for construction contracts must be established in the manner required under the city's minority and women-owned business enterprises utilization plan.

Subd. 8.Conduit bond issuance.

(a) Upon the request of the corporation or the nonprofit agency, the city or its economic development authority shall issue revenue bonds or other similar obligations for a qualifying project. "Revenue bonds or other obligations" as used in this subdivision means bonds or other obligations issued under sections 469.152 to 469.165 or under chapter 462C, the interest on which is tax exempt. The city or its development authority shall use its best efforts to issue the bonds or other obligations as promptly and efficiently as possible following the request and the provision of the information and completion of the actions by the corporation or the nonprofit agency that are necessary for the issuance. Upon request of the corporation or nonprofit agency, the city or its economic development authority shall adopt methods and procedures that preserve the confidentiality of private donors or other private participants in the qualifying project, including structures and methods that do not require disclosing information on the donors or participants to the city or its economic development authority, and shall segregate in separate accounts all funds related to a qualifying project from other city and authority funds.

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

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 Seventh Place East, Suite 350
St Paul, MN 55101-2147

IN THE MATTER OF THE APPLICATION OF MINNESOTA ENERGY RESOURCES CORPORATION FOR AUTHORITY OF RIDER RECOVERY FOR THE ROCHESTER NATURAL GAS EXTENSION FOR NATURAL GAS SERVICE IN MINNESOTA

MPUC Docket No. G011/M-15-895
OAH Docket No. 68-2500-3319

DIRECT ATTACHMENTS OF ADAM J. HEINEN (PART III – AJH-6 TO AJH-28, PAGES 14 TO 21 AND AJH-29)

ON BEHALF OF

THE MINNESOTA DEPARTMENT OF COMMERCE DIVISION OF ENERGY RESOURCES

FINANCIAL ISSUES

JULY 1, 2016

(b) For purposes of this section, a "qualifying project" means a project, as that term is defined in section 469.153, or a project that would qualify for financing under chapter 462C, that:

(1) the corporation finds is consistent with and will further the goals of the development plan;

(2) is located in a medical development district; and

(3) has a commitment of private funding sources such as donations of money or in-kind contributions, other than revenues generated by the project, equal to at least ten percent of the total capital cost of the project.

Subd. 9.Public bidding exemption.

(a) Notwithstanding section 469.068 or any other law to the contrary, the city need not require competitive bidding with respect to a parking facility or other public improvements constructed in conjunction with, and directly above or below, or adjacent and integrally related to, a private development financed or developed under the development plan.

(b) For purposes of this section, "city" includes the development authority established by the city.

History:

2013 c 143 art 10 s 7; 2015 c 1 s 7

NOTE: The amendment to subdivision 5 by Laws 2015, chapter 1, section 7, is effective after the governing body of the city of Rochester and its chief clerical officer timely comply with Minnesota Statutes, section 645.021, subdivisions 2 and 3, and applies retroactively to the original effective dates of the provisions of law that are amended. Laws 2015, chapter 1, section 13.

469.45 CITY TAX AUTHORITY.

Subdivision 1.Rochester, other local taxes authorized.

(a) Notwithstanding section 477A.016 or any other contrary provision of law, ordinance, or city charter, and in addition to any taxes the city may impose on these transactions under another statute or law, the city of Rochester may, by ordinance, impose at a rate or rates, determined by the city, any of the following taxes:

(1) a tax on the gross receipts from the furnishing for consideration of lodging and related services as defined in section 297A.61, subdivision 3, paragraph (g), clause (2); the city may choose to impose a differential tax based on the number of rooms in the facility;

(2) a tax on the gross receipts of food and beverages sold primarily for consumption on the premises by restaurants and places of refreshment that occur in the city of Rochester; the city may elect to impose the tax in a defined district of the city; and

(3) a tax on the admission receipts to entertainment and recreational facilities, as defined by ordinance, in the city of Rochester.

(b) The provisions of section 297A.99, subdivisions 4 to 13, govern the administration, collection, and enforcement of any tax imposed by the city under paragraph (a).

(c) The proceeds of any taxes imposed under this subdivision, less refunds and costs of collection, must be used by the city only to meet its share of obligations for public infrastructure projects contained in the development plan and approved by the corporation, including any associated financing costs or to pay any other costs qualifying as a local matching contribution under section 469.47, subdivision 4. Any tax imposed under paragraph (a) expires at the earlier of December 31, 2049, or when the city council determines that sufficient funds have been raised from the tax plus all other local funding sources authorized in Laws 2013, chapter 143, article 10, to meet the city obligation for financing public infrastructure projects contained in the development plan and approved by the corporation, including any associated financing costs.

[See Note.]

Subd. 2.General sales tax authority.

The city may elect to extend the existing local sales and use tax under Laws 2013, chapter 143, article 10, section 13, or to impose an additional rate of up to one quarter of one percent tax on sales and use under Laws 2013, chapter 143, article 10, section 11. The proceeds of any extended or additional taxes imposed under this subdivision, less refunds and costs of collection, must be used by the city only to meet its share of obligations for public infrastructure projects contained in the development plan and approved by the corporation, including all financing costs. Revenues collected in any year to meet the obligations must be used for payment of obligations or expenses for public infrastructure projects approved by the corporation or of any other costs qualifying as a local matching contribution under section 469.47, subdivision 4.

[See Note.]

Subd. 3.Special abatement rules.

(a) If the city or the county elects to use tax abatement under sections 469.1812 to 469.1815 to finance costs of public infrastructure projects, including all financing costs, the special rules under this subdivision apply. Taxes abated for public infrastructure projects must be used only for obligations or other infrastructure projects approved by the corporation.

(b) The limitations under section 469.1813, subdivision 6, do not apply to the city or the county.

(c) The limitations under section 469.1813, subdivision 8, do not apply and property taxes abated by the city or the county to finance costs of public infrastructure projects are not included for purposes of applying section 469.1813, subdivision 8, to the use of tax abatement for other purposes of the city or the county; however, the total amount of property taxes abated by the city and the county under this authority must not exceed $87,750,000.

Subd. 4.Special tax increment financing rules.

If the city elects to establish one or more redevelopment tax increment financing districts within the area of the destination medical center development district to fund public infrastructure projects, the requirements, definitions, limitations, or restrictions in the following statutes do not apply: sections 469.174, subdivisions 10 and 25, clause (2); 469.176, subdivisions 4j, 4l, and 5; and 469.1763, subdivisions 2, 3, and 4. The provisions of this subdivision expire effective for tax increments expended after December 31, 2049. After that date, the provisions of section 469.1763, subdivision 4, apply to any remaining unspent or unobligated increments.

History:

2013 c 143 art 10 s 8; 1Sp2015 c 1 art 8 s 3,4

NOTE: The amendments to subdivisions 1 and 2 by Laws 2015, First Special Session chapter 1, article 8, sections 3 and 4, are effective the day after the governing body of the city of Rochester and its chief clerical officer comply with Minnesota Statutes, section 645.021, subdivisions 2 and 3, and apply retroactively to the original effective dates of the laws that are amended. Laws 2015, First Special Session chapter 1, article 8, sections 3 and 4, the effective dates.

469.46 COUNTY TAX AUTHORITY.

(a) Notwithstanding sections 297A.99, 297A.993, and 477A.016, or any other contrary provision of law, ordinance, or charter, and in addition to any taxes the county may impose under another law or statute, the Board of Commissioners of Olmsted County may, by resolution, impose a transit tax of up to one quarter of one percent on retail sales and uses taxable under chapter 297A. The provisions of section 297A.99, subdivisions 4 to 13, govern the imposition, administration, collection, and enforcement of the tax authorized under this paragraph.

(b) The Board of Commissioners of Olmsted County may, by resolution, levy an annual wheelage tax of up to $10 on each motor vehicle kept in the county when not in operation which is subject to annual registration and taxation under chapter 168, for transportation projects within the county. The wheelage tax must not be imposed on the vehicles exempt from wheelage tax under section 163.051, subdivision 1. The board, by resolution, may provide for collection of the wheelage tax by county officials, or it may request that the tax be collected by the state registrar on behalf of the county. The provisions of section 163.051, subdivisions 2, 2a, 3, and 7, must govern the administration, collection, and enforcement of the tax authorized under this paragraph. The tax authorized under this section is in addition to any tax the county may be authorized to impose under section 163.051, but until January 1, 2018, the county tax imposed under this paragraph, in combination with any tax imposed under section 163.051, must equal the specified rate under section 163.051.

(c) The proceeds of any taxes imposed under paragraph (a), less refunds and costs of collection, must be first used by the county to meet its local matching contributions under section 469.47, subdivision 6, for financing transit infrastructure related to the public infrastructure projects contained in the development plan and approved by the corporation, including any financing costs. Revenues collected in any calendar year in excess of the county obligation to pay for projects contained in the development plan may be retained by the county and used for funding other transportation projects, including roads and bridges, airports, and transportation improvements.

(d) Any taxes imposed under paragraph (a) expire December 31, 2049, or at an earlier time if approved by resolution of the county board of commissioners. The taxes must not terminate before the county board of commissioners determines that revenues from these taxes and any other revenue source the county dedicates are sufficient to pay the county share of transit project costs and financing costs under the development plan.

History:

2013 c 143 art 10 s 9

469.47 STATE INFRASTRUCTURE AID.

Subdivision 1.Definitions.

(a) For purposes of this section, the following terms have the meanings given them.

(b) "Commissioner" means the commissioner of employment and economic development.

(c) "Construction projects" means:

(1) for expenditures by a medical business entity, construction of buildings in the city for which the building permit was issued after June 30, 2013; and

(2) for any other expenditures, construction of privately owned buildings and other improvements that are undertaken pursuant to or as part of the development plan and are located within a medical center development district.

(d) "Expenditures" means expenditures made by a medical business entity or by an individual or private entity on construction projects for the capital cost of the project including, but not limited to:

(1) design and predesign, including architectural, engineering, and similar services;

(2) legal, regulatory, and other compliance costs of the project;

(3) land acquisition, demolition of existing improvements, and other site preparation costs;

(4) construction costs, including all materials and supplies of the project; and

(5) equipment and furnishings that are attached to or become part of the real property.

Expenditures excludes supplies and other items with a useful life of less than a year that are not used or consumed in constructing improvements to real property or are otherwise chargeable to capital costs.

(e) "Qualified expenditures for the year" means the total certified expenditures since June 30, 2013, through the end of the preceding year, minus $200,000,000.

(f) "Transit costs" means the portions of a public infrastructure project that are for public transit intended primarily to serve the district, such as transit stations, equipment, rights-of-way, and similar costs.

[See Note.]

Subd. 2.Certification of expenditures.

By April 1 of each year, the medical business entity must certify to the commissioner the amount of expenditures made by the medical business entity in the preceding year. For expenditures made by an individual or entity other than the medical business entity, the corporation shall compile the information on the expenditures and may certify the amount to the commissioner. The certification must be made in the form that the commissioner prescribes and include any documentation of and supporting information regarding the expenditures that the commissioner requires. By August 1 of each year, the commissioner must determine the amount of the expenditures for the preceding year.

Subd. 3.General state infrastructure aid.

(a) The amount of the general state infrastructure aid for a year equals the qualified expenditures for the year, as certified by the commissioner, multiplied by 2.75 percent. The maximum amount of state aid payable in any year is limited to no more than $30,000,000. If the commissioner determines that the city has made the required matching local contribution under subdivision 4, the commissioner must pay to the city the amount of general state infrastructure aid for the year by September 1. If the commissioner determines that the city has not made the full required matching local contribution for the year, the commissioner must pay only the aid permitted under the agreement for the matching contribution made and any unpaid amount is a carryover aid. The carryover aid must be paid in the first year after the required matching contribution is made and in which the aid entitlement for the current year is less than the maximum annual limit, but only to the extent the carryover, when added to the current year aid, is less than the maximum annual limit.

(b) The city must use general state infrastructure aid it receives under this subdivision for improvements and other capital costs related to the public infrastructure projects approved or adopted by the corporation, other than transit costs. The city must maintain appropriate records to document the use of the funds under this requirement.

(c) The commissioner, in consultation with the commissioner of management and budget, and representatives of the city and the corporation, must establish a total limit on the amount of state aid payable under this subdivision that will be adequate to finance, in combination with the local contribution, $455,000,000 of general public infrastructure projects.

[See Note.]

Subd. 4.General aid; local matching contribution.

In order to qualify for general state infrastructure aid, the city must enter a written agreement with the commissioner that requires the city to make a qualifying local matching contribution to pay for $128,000,000 of the cost of public infrastructure projects approved by the corporation, including financing costs, using funds other than state aid received under this section. The required local matching contribution is reduced by any amounts the city pays out of funds other than state aid received under this section for the support, administration, or operations of the corporation and the economic development agency up to a maximum amount agreed to by the board and the city. These amounts include any costs the city incurs in providing services, goods, or other support to the corporation or agency. The agreement must provide for the manner, timing, and amounts of the city contributions, including the city's commitment for each year. Notwithstanding any law to the contrary, the agreement may provide that the city contributions for public infrastructure project principal costs may be made over a 20-year period at a rate not greater than $1 from the city for each $2.55 from the state. The local match contribution may be provided by the city from any source identified in section 469.45 and any other local tax proceeds or other funds from the city and may include providing funds to prepare the development plan, to assist developers undertaking projects in accordance with the development plan, or by the city directly undertaking public infrastructure projects in accordance with the development plan, provided the projects have been approved by the corporation. City contributions that are in excess of this ratio carry forward and are credited toward subsequent years. The commissioner and city may agree to amend the agreement at any time in light of new information or other appropriate factors. The city may enter into arrangements with the county to pay for or otherwise meet the local matching contribution requirement. Any public infrastructure project within the area that will be in the destination medical center development district whose implementation is started or funded by the city after June 22, 2013, but before the development plan is adopted, as provided by section 469.43, subdivision 1, will be included for the purposes of determining the amount the city has contributed as required by this section and the agreement with the commissioner, subject to approval by the corporation.

[See Note.]

Subd. 5.State transit aid.

(a) The city qualifies for state transit aid under this section if the county contributes the required local matching contribution under subdivision 6 or the city or county has agreed to make an equivalent contribution out of other funds for the year.

(b) If the city qualifies for aid under paragraph (a), the commissioner must pay the city the state transit aid in the amount calculated under this paragraph. The amount of the state transit aid for a year equals the qualified expenditures for the year, as certified by the commissioner, multiplied by 0.75 percent, reduced by the amount of the local contribution under subdivision 6. The maximum amount of state transit aid payable in any year is limited to no more than $7,500,000. If the commissioner determines that the city or county has not made the full required matching local contribution for the year, the commissioner must pay state aid only in proportion to the amount of the matching contribution made for the year and any unpaid amount is a carryover aid. The carryover aid must be paid in the first year after the required matching contribution for that prior year is made and in which the aid entitlement for the current year is less than the maximum annual limit, but only to the extent the carryover, when added to the current year aid, is less than the maximum annual limit.

(c) The commissioner, in consultation with the commissioner of management and budget, and representatives of the city and the corporation, must establish a total limit on the amount of state aid payable under this subdivision that will be adequate to finance, in combination with the local contribution, $116,000,000 of transit costs.

(d) The city must use state transit aid it receives under this subdivision for transit costs. The city must maintain appropriate records to document the use of the funds under this requirement.

[See Note.]

Subd. 6.Transit aid; local matching contribution.

(a) The required local matching contribution for state transit aid equals the lesser of:

(1) 40 percent of the state transit aid under subdivision 5; or

(2) the amount that would be raised by a 0.15 percent sales tax imposed by the county in the preceding year.

The county may impose the sales tax or the wheelage tax under section 469.46 to meet this obligation.

(b) If the county elects not to impose any of the taxes authorized under section 469.46, the county, or city, or both, may agree to make the local contribution out of other available funds, other than state aid payable under this section. The commissioner of revenue must estimate the required amount and certify it to the commissioner, city, and county.

Subd. 7.Prevailing wage requirement.

During the construction, installation, remodelling, and repairs of any public infrastructure project funded by state aid or a local matching contribution under this section, laborers and mechanics at the site must be paid the prevailing wage rate as defined in section 177.42, subdivision 6, and the project is subject to the requirements of sections 177.30 and 177.41 to 177.44.

Subd. 8.Termination.

No aid may be paid under this section after fiscal year 2049.

Subd. 9.Appropriation.

An amount sufficient to pay the state general infrastructure and state transit aid authorized under this section is appropriated to the commissioner from the general fund.

History:

2013 c 143 art 10 s 10; 2015 c 1 s 8-11; 1Sp2015 c 1 art 8 s 5

NOTE: The amendments to subdivisions 1, 3, and 5 by Laws 2015, chapter 1, sections 8, 9, and 11, are effective after the governing body of the city of Rochester and its chief clerical officer timely comply with Minnesota Statutes, section 645.021, subdivisions 2 and 3, and apply retroactively to the original effective dates of the provisions of law that are amended. Laws 2015, chapter 1, section 13.

NOTE: The amendment to subdivision 4 by Laws 2015, chapter 1, section 10, as amended by Laws 2015, First Special Session chapter 1, article 8, section 5, is effective the day after the governing body of the city of Rochester and its chief clerical officer comply with Minnesota Statutes, section 645.021, subdivisions 2 and 3, and applies retroactively to the original effective dates of the provisions of laws that are amended. Laws 2015, chapter 1, section 13; Laws 2015, First Special Session chapter 1, article 8, section 5, the effective date

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.	
28	Subject: Phase II Costs

Reference: Lee Direct, Page 16, Table 1

Please fully discussion whether any of the costs projected in Table 1 are anticipated to be incurred within the boundaries of the Destination Medical Center district.

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:

None. As noted in the Direct Testimony of Lindsay K. Lyle, the work for Phase II of the Rochester Project essentially involves building a connection from existing TBS 1B to existing TBS 1D and creating a new TBS. This new construction essentially ties the northern and southern parts of Rochester more closely together. As depicted on Figure 1 on page 6 of Ms. Lyle's Direct Testimony, the work on Phase II goes from the northwestern part of

Response by: Amber Lee

Title: Regulatory and Leg. Affairs Mgr.

Department: Regulatory Affairs

Telephone: (651) 322-8965

List sources of information:

Rochester and loops around to the southeast. As such, the work essentially goes around the perimeter of the City but does not generally physically touch the City.

See MERC's response to Department Information Request No. 27 for additional context on the benefits and costs of the project as distinguished from where the work is physically located.

Response by: Amber Lee

Title: Regulatory and Leg. Affairs Mgr.

Department: Regulatory Affairs

Telephone: (651) 322-8965

List sources of information: