BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
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FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
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Nancy Lange	Commissioner
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
John 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	MPUC Docket No. G-011/M-15-895 OAH Docket No. 2500-33191

PROPOSED FINDINGS OF FACT OF THE MINNESOTA DEPARTMENT OF COMMERCE, DIVISION OF ENERGY RESOURCES

Dated: October 28, 2016

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TABLE OF CONTENTS

I. INTRODUCTION

The Minnesota Department of Commerce, Division of Energy Resources, Energy Regulation and Planning Unit (Department or DOC) respectfully submits these Proposed Findings of Fact (Findings) to assist the Administrative Law Judge (ALJ) and the Minnesota Public Utilities Commission (Commission) the Petition of Minnesota Energy Resources Corporation (MERC or the Company) for Evaluation and Approval of Rider Recovery for Its Rochester Natural Gas Extension Project. The Department's Initial Brief was the principal document used to create these Proposed Findings of Fact and the headings are left intact to assist the reader.

II. PROCEDURAL HISTORY

1. On October 26, 2015, MERC filed a petition for evaluation and approval of rider recovery for its Rochester Natural Gas Extension Project (Rochester Project or Project) under Minn. Stat. § 216B.1638 (2015), the natural gas extension project statute (NGEP Statute). MERC's was the first petition to be filed under the NGEP Statute, which was enacted in 2015.

2. MERC supplemented its petition on December 7, 2015. 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.

3. 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.

4. By November 25, the Commission received initial comments from 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 MERC.

5. Between December 24 and January 5, the Department and the OAG filed reply comments, and MERC filed a response to the Department's reply. On January 14, 2016, the Commission met to consider the matter.

6. On February 8, 2016 the Commission issued its Notice of and Order for Hearing in this Docket, 15-895, and in the MERC 2015 Rate Case[1] in which it found MERC's petition substantially complete, and referred the petition to the OAH for contested-case proceedings. The Commission referred MERC's petition as a separate, standalone contested case, moved all Rochester Project Phase II costs and issues from the MERC 2015 Rate Case to this 15-895 docket and requested that, to the extent practicable, the ALJ return a report by November 30, 2016. The Commission further requested that the OAH hold public hearings in Rochester and other locations in MERC's service area, and that the OAH add the City of Rochester, Mayo Clinic, and the Destination Medical Center (DMC) 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, with MERC to provide contact information, if needed. The Commission identified the parties to the case as MERC, the Department, and the OAG.

7. In the February 8, 2016 Notice of and Order for Hearing, the Commission further requested 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?[2]

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

8. The Commission's February 8, 2016 Notice of and Order for Hearing further deferred 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.

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[1] *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates For Natural Gas Service in Minnesota*, Docket No. G011/GR-15-736; OAH Docket No. 68-2500-32993 (MERC 2015 Rate Case).

[2] The Commission stated that "[t]his 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."

[3] The Commission observed that "[o]ne 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."

9. On March 3, 2016, the ALJ held a Prehearing Conference.

10. On March 9, 2016, the ALJ issued a First Prehearing Order that granted NNG's Petition to Intervene, and set procedures for parties and participants in the case. The ALJ added to the service list the names of persons who have filed a Notice of Appearance and well as the names of representatives of the City of Rochester, the DMC Economic Development Agency, the Mayo Clinic, and Rochester Public Utilities to the Service List maintained by the Commission. The First Prehearing Order established, with the agreement of the parties and participants to the prehearing conference, the following schedule:

Milestone	**Due Date**
MERC Direct Testimony	April 15, 2016
Deadline for Intervention	May 16, 2016
Intervenors' Pre-Filed Direct Testimony	July 1, 2016
Public Hearings in Greater Minnesota (Albert Lea, Cloquet, Rochester, and Rosemount)	July 11-15, 2016 (tentative)
All Parties' Rebuttal Testimony	July 28, 2016
All Parties' Surrebuttal Testimony	August 25, 2016
Prehearing Conference	September 1, 2016, at 1:30 p.m. at the MPUC offices in St. Paul
Evidentiary Hearings – Saint Paul	September 6-September 9, 2016 at the MPUC offices, St. Paul. The evidentiary hearing will begin at 9:30 a.m., September 6, 2016
All Parties' Initial Briefs	October 11, 2016
All Parties' Reply Briefs and Proposed Findings of Fact and Conclusions of Law	October 25, 2016
Report of the Administrative Law Judge	November 30, 2016

11. On April 14, 2016, the ALJ issued a Highly-Sensitive Trade Secret Protective Order (HSTS Order) and caused to be opened MPUC Docket No. G011/M-16-315 for the filing of HSTS data.

12. The ALJ issued an Order on May 2, 2016, granting the Petition for Intervention of the Super Large Gas Intervenors.

13. On August 30, the ALJ issued the Second Prehearing Order setting a telephonic prehearing conference for Thursday, September 1, 2016 at 1:30 p.m. A prehearing conference was held on September 1, 2016.

14. The contested case evidentiary hearing was held on September 6 and 7, 2016.

15. Parties' initial briefs were filed on October 11, 2016, and reply briefs were filed on October 25, 2016

III. STATEMENT OF THE ISSUES

16. The Commission's February 8, 2016 Notice of and Order for Hearing requested 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?[4]
    4. What other funds may be available to cover the project costs?[5]

IV. PROPOSED FINDINGS OF FACT

1. BURDEN OF PROOF

17. A utility bears the burden of showing that its proposed rates are just and reasonable. Minn. Stat. § 216B.16, subd. 4 (2014); *In re Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket No. G-008/GR-13-316, Findings of Fact, Conclusions, and Order at 3 (June 9, 2014) (*citing* Minn. Stat. § 216B.16, subd. 4, 5, and 6) (CenterPoint 2013 Rate Case Order). This burden is affirmative.

18. In this case, even though the Commission deferred any decision on the accuracy of MERC's revenue-deficiency calculation until the Company seeks approval of an NGEP rider to recover the specific revenue deficiency, MERC bears the burden of proof to show the prudency and reasonableness of the estimated costs, given MERC's stated intention to seek recovery in the future. That is, a record that fails to show affirmatively that costs were prudently and reasonably incurred falls short of satisfying MERC's burden of proof.

19. The burden is on the utility to prove the facts required to sustain its burden by a fair preponderance of the evidence. The Court in *In re Northern States Power Co.*, 416 N.W.2d 719, 722 (Minn. 1987) described the Commission's role, both quasi-judicial and quasi-legislative, in determining just and reasonable rates in a rate proceeding, including the Commission's role in evaluating whether the utility has met its burden to show the reasonableness of recovering particular costs from ratepayers:

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4 See Note 1 above.
5 See Note 2 above.

> [I]n the exercise of the statutorily imposed duty to determine whether the inclusion of the item generating the claimed cost is appropriate, or whether the ratepayers or the shareholders should sustain the burden generated by the claimed cost, the MPUC acts in both a quasi-judicial and a partially legislative capacity. To state it differently, in evaluating the case, the accent is more on the inferences and conclusions to be drawn from the basic facts (*i.e.*, the amount of the claimed costs) rather than on the reliability of the facts themselves. Thus, *by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses*.

Id. at 722–23 (citation omitted) (emphasis added). Moreover, the Court held that the utility "had at all times the burden of proving the proposed rate change." A utility does not enjoy at any point in a proceeding to determine rates, a rebuttable presumption of reasonableness that other parties must overcome. *Id.* at 725-26.

20. Any doubt as to whether the utility satisfied its burden of proof must be resolved in favor of the consumer:

> Every rate made, demanded or received by a public utility . . . shall be just and reasonable. . . . Any doubt as to reasonableness should be resolved in favor of the consumer.

Minn. Stat. § 216B.03 (2014).

21. To the extent that MERC did not satisfy its burden of demonstrating that its investment in the Rochester Project and requested cost recovery method from ratepayers was prudent and reasonable, the Department recommended adjustments to the Company's request to conform to the requirement that rates must be fair and reasonable. The fact that the Department has not recommended complete disallowance of MERC's requests, even though MERC did not show the reasonableness of its entire request does not mean that at any point in this proceeding the burden of proof shifted to the Department to demonstrate imprudence or unreasonableness.

2. INTRODUCTION–PROJECT DESCRIPTION

22. The Rochester Project involves upgrading MERC's local distribution network in the Rochester Area,[6] improvements to NNG's 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. The Rochester Project has two phases. Phase I has

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

already been constructed and its recovery was included in the MERC 2015 Rate Case.[7] Phase I involved upgrades to deliverability on MERC's distribution system in the Rochester Area. DOC Ex. 405 at 3-4 (Heinen Direct).

23. Phase II involves reconstruction of the TBSs that serve Rochester and construction of the transmission infrastructure to move additional capacity into the Rochester Area. MERC asserts in this 15-895 Docket that the costs associated with Phase II are eligible for rider recovery, to be authorized under the new NGEP Statute, Minn. Stat. § 216B.1638 (2015). DOC Ex. 405 at 4 (Heinen Direct).

24. This case is the first time that a gas utility has sought rate recovery under this new law, and, in this respect, the Project differs from all past natural gas expansion projects intended to increase capacity in a given geographic area. DOC Ex. 405 at 5 (Heinen Direct).

25. The NGEP Statute provides unique cost recovery mechanisms. If the proposing gas utility can show that costs are reasonable and prudent, the NGEP Statute allows the utility to recover up to 33 percent of annual project costs through a rider. The costs in the rider, as well as the remaining 67 or more percent of costs, are then "rolled" into rate base in a future general rate case.

26. The NGEP Statute permits rider treatment of costs 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." Minn. Stat. § 216B.1638 subd.1(i).

27. Under the NGEP Statute, the NGEP rider "shall include all of the utility's customers, including transport customers, to recover the revenue deficiency from a natural gas extension project." This latter aspect of cost recovery importantly prevents MERC's large customers from receiving an undue incentive to switch to transportation service solely to avoid the costs of this Project. DOC Ex. 405 at 5-6 (Heinen Direct).

28. MERC notified the Department of the need for expansion in Rochester on or about October 22, 2014. DOC Ex. 405 at 4 (Heinen Direct). The goals of the Project have not changed since the October 2014 notification; however, the Company's current plan to increase capacity differs materially from the potential projects MERC presented to the Department in the planning phase. For example, in its October 2014 presentation to the Department, MERC said that it anticipated total Project costs upwards of $170 million, not including contingencies, which is significantly greater than the approximately $60 million in projected NNG project costs proposed in this 15-895 Docket. DOC Ex. 405 at 4-5 and AJH-5 (Heinen Direct) (*citing* MERC Ex. 5 at 2 (Lee Direct). In discussions with the Department and other state agencies, MERC streamlined and improved its proposed Project, including by issuance of a request for proposals (RFP) and negotiations

[7] At the time of this writing, the Commission has completed deliberations on the MERC 2015 Rate Case, but has not yet issued a written order.

with counterparties to lower construction and capacity costs. The efforts of MERC, the Department, and other state agencies prior to the filing of this proposal have already saved ratepayers many millions of dollars in Project costs. These RFP-related negotiations resulted in improved terms and better flexibility for MERC and its ratepayers. DOC Ex. 405 at 5 (Heinen Direct).

3. THE DEPARTMENT'S ANALYSIS OF FORECASTED NEED CONFIRMS THAT THE ROCHESTER PROJECT IS PRUDENT AND REASONABLE.

29. Forecasted need is disputed among MERC, the Department and the OAG; however the results of the DOC and MERC's separate and independent analyses each confirmed that the Project is prudent and reasonable, while the OAG proposed a smaller, more incremental approach to capacity expansion.

A. Overview

30. The Department reviewed and identified concerns regarding the Company's forecast and conducted an alternative need forecast. Based on that alternative forecast, the Department concluded that MERC's forecasted need was appropriate, but likely represented an optimistic view of growth, while the Department's alternative forecast represented a "status quo" estimate of expected demand. *Id.* at 2. While MERC's analysis needed improvement, the results of MERC's analysis were not significantly different than the results of the Department's alternative analysis. DOC Ex. 410 at 1-2 (Heinen Summary).

31. The Department also concluded, unlike the OAG, that the temporary excess capacity costs associated with the Project were relatively small on an annual basis and were acceptable relative to the risks associated with a smaller or "phased" potential project, such as was recommended by the OAG. DOC Ex. 410 at 1-2 (Heinen Summary). Based on the potential risks and cost considerations of building a smaller project, the Department concluded that the Project, as proposed, was reasonable. DOC Ex. 410 at 3 (Heinen Summary). The Department agreed with the OAG that there has been considerable fluctuation in firm demand on MERC's system, but concluded that this fluctuation helps support the Project because it is critical for MERC to be able to provide reliable natural gas service during cold winter periods when firm demand is high. DOC Ex. 410 at 2 (Heinen Summary).

B. MERC's Need Analysis Was Inadequate.

32. MERC's long-range sales forecast is unusual because natural gas utilities do not typically produce medium- to long-range forecasts for purposes of utility regulation. Unlike electric utilities in Minnesota, which are required to regularly file integrated resource plans,[8] Minnesota's regulated natural gas utilities are not subject to Commission review

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8 *See* Minn. Stat. § 216B.2422 and Minn. R. Ch. 7842.

of their long-range expansion plans, procurement plans, or expected growth. DOC Ex. 405 at 7 (Heinen Direct).

1. Description of MERC's Methodology for Forecast of Sales.

33. MERC used a two-stage process to forecast need for its Project. To estimate firm peak load at each of the TBSs in the Rochester Area, the Company used historical data from January 2007 to July 2015 to forecast sales, customer counts by individual rate class, from August 2015 through December 2025, and heating season data[9] from December 2012 to February 2015. DOC Ex. 405 at 4-6 (Heinen Direct) (*citing* MERC Ex. 9 at 7 (Clabots Direct)). MERC 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, MERC's expected growth in firm peak demand was driven by the results of the firm rate class sales forecasts. DOC Ex. 405 at 6 (Heinen Direct) (*citing* MERC Ex. 3 at C8 through C18 (Initial Filing)).

34. Generally, MERC's method to estimate sales in this proceeding was similar to the method MERC used for its short-term sales forecast in the MERC 2015 Rate Case (DOC Ex. 405 at 7-8 (Heinen Direct)) and its estimate of 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).

35. Annual natural gas demand entitlement filings focus on the amount of reserved pipeline capacity needed to serve the gas-supply needs of firm sales customers. The planning objective in demand entitlement proceedings is to ensure that MERC can provide service over the coldest 24-hour average wind adjusted heating degree day (AHDD) day for each regression area.[10]

36. For the Rochester Area, the coldest AHDD day occurred in 1996 and was 101 AHDD, or approximately an average daily adjusted temperature of minus 36 degrees Fahrenheit. DOC Ex. 405 at 8 (Heinen Direct).

37. Peak demand represents the maximum daily natural gas throughput on a utility's system. Importantly, peak demand as it relates to this docket and to demand entitlement filings is slightly different. 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 such analyses because interruptible customers receive the benefit of

[9] MERC's heating season data is for the months of December through February of each year. DOC Ex. 405 at 4-6 (Heinen Direct) (*citing* MERC Ex. 9 at 7 (Clabots Direct)).

[10] In these filings, the Company used daily data for the 2012-2014 heating seasons to determine the relationship between weather (defined as adjusted HDDs or AHDDs) and firm throughput. MERC 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 its analysis by applying statistical-based risk factors to each regression models to better estimate peak day throughput. DOC Ex. 405 at 8 (Heinen Direct).

paying lower non-gas margins in return for agreeing to service interruption when load is 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 natural gas entitlement level from a third-party vendor, not the gas utility. DOC Ex. 405 at 8-9 (Heinen Direct).

38. Peak demand is different in this proceeding because here, MERC 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 of the pipeline NNG owns that is serving the Rochester Area, without regard to the type of customer that uses the incremental pipeline capacity. DOC Ex. 405 at 9 (Heinen Direct).

39. In its demand entitlement filings, the Company had estimated peak demand for the Rochester Area using a single regression model. DOC Ex. 405 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.[11] DOC Ex. 405 at 9-10 and AJH-7 (Heinen Direct).

40. For its peak demand forecast in this 15-895 docket, MERC used a basic estimation methodology that was similar to the method it employed in its most recent demand entitlement filings, but using different model specifications. DOC Ex. 405 at 10 (Heinen Direct). In this 15-895 proceeding, 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 difference in design and purpose between this analysis and the analysis in demand entitlement filings. Here, the Company assumed normal weather in its use-per-customer (UPC) and sales models. MERC calculated and defined normal weather in the same manner as it did in the MERC 2015 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. The normal weather data used in this 15-985 docket were the same as the data used in the MERC 2015 Rate Case. 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. DOC Ex. 405 at 10 (Heinen Direct).

41. MERC's sales and demand projections in this 15-895 docket 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. 9 at 13 (Clabots Direct).

[11] The results of MERC's peak demand analysis for this 15-895 docket are at DOC Ex. 405 at AJH-7 (Heinen Direct) (MERC Response to DOC IR No. 16).

42. The impacts of the DMC was implicitly included, however, because the Company included regional demographic and economic factors when it estimated and forecast sales for certain rate classes. That 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.[12] DOC Ex. 405 at 11 (Heinen Direct).

43. Further information in the record regarding drivers for the need for the Rochester Project includes two documents: a City of Rochester's "Proclamation" and a "2015 Update of the [Rochester Public Utility] RPU Infrastructure Study" dated June 2015 by Burns and McDonnell for RPU (RPU Infrastructure Report). DOC Ex. 405 at 11, AJH-3 and AJH-4 (Heinen Direct).

44. 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. DOC Ex. 405 at 12 (Heinen Direct).

45. The RPU Infrastructure Report discusses renewable generation but places significant emphasis on the importance of natural gas for electric generation, and the potential replacement of existing generating facilities in the Rochester Area. This information is important because the Rochester Area is capacity-constrained with respect to natural gas. That 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, means that RPU's needs are an important factor to consider in this proceeding. DOC Ex. 405 at 12 (Heinen Direct). It is unclear how RPU intends to procure service, but it announced recently that it plans to rebuild its Westside Energy Station and use natural gas as its fuel source. DOC Ex. 405 at 12 and AJH-25 (Heinen Direct).

46. 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 a steam contract with Mayo, c) is considering developing a combined heat and power facility to be powered by natural gas and d) expects to need a combined cycle natural gas facility in the future. DOC Ex. 405 at 10 (Heinen Direct).

47. 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

[12] The final results of MERC's need forecast are in the evidentiary record at DOC Ex. 405 at 11, AJH-7 and AJH-8 (Heinen Direct) (Responses to DOC IR Nos. 16 and 18).

> 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. 405 at 12-13 and AJH-4, p. 3-2 and 3-3 (Heinen Direct).

2. The Department's Review of MERC's Need Analysis

48. The Department reviewed the Company's model outputs for the sales and peak demand models and was able to replicate MERC's regression results using its input data and model specifications. DOC Ex. 405 at 13 (Heinen Direct).

49. The Department observed several concerns with the Company's methodology that could call into question the validity of the Company's need analysis.[13] DOC Ex. 405 at 13 (Heinen Direct).

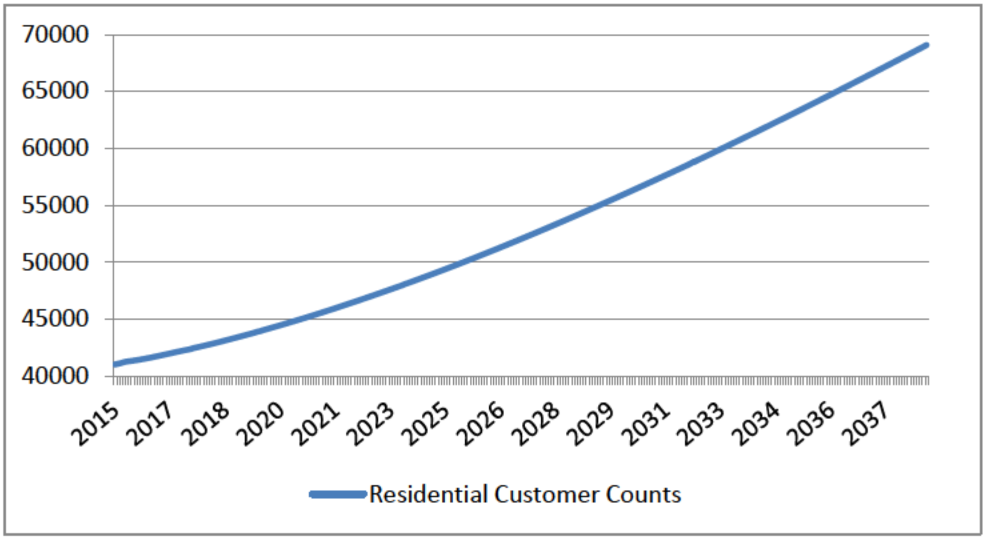
a. MERC's Projected Sales Growth Represented the Higher Range of Expected Growth for the Rochester Area.

50. MERC's estimates of sales growth for the Residential and Small Commercial/Industrial rate classes (as noted above) were based on use per customer (UPC) models, which also require forecasted customer growth to estimate total sales into the forecasting period. DOC Ex. 405 at 14 (Heinen Direct).

51. The results of the Company's Residential customer growth model are plotted in Heinen Direct Graph 1 below.

[13] Because of the concerns with the reasonableness of the Company's proposed need, the Department performed an independent analysis, discussed below. *See also* DOC Ex. 405 at 14 (Heinen Direct).

Heinen Direct Graph 1: Residential Customer Count Forecast for the Rochester Area



DOC Ex. 405 at 15 (Heinen Direct).

52. The results of the Company's customer count forecast suggested that growth would increase significantly, over time, into the forecast period. MERC's forecast assumed annual Residential customer count growth in the Rochester Area of approximately 2.26 percent. MERC also provided population forecasts from the Rochester-Olmsted Council of Governments (ROCG) in its Direct Testimony.[14] DOC Ex. 405 at 15 and AJH-9 (Heinen Direct) (*citing* MERC Ex. 9 at DWC-2, p. 7 of 14 (Clabots Direct).

53. The Department tested the reliability of the population growth data by comparing the results of MERC's residential customer count forecast to historical *household* data because, in many respects, customer counts for a utility are analogous to the number of households in an area.[15] DOC Ex. 405 at 16 (Heinen Direct).[16]

[14] The ROCG population forecast data did not anticipate growth at the level projected by the Company. 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. Population growth estimates and customer count estimates are not entirely comparable, however. Population looks at the number of people in an area, while customer counts look at the number of utility meters in an area. DOC Ex. 405 at 15-16 (Heinen Direct).

[15] Department Witness Mr. Heinen explained that it necessary to analyze the historical relationship between household size and population because 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. DOC Ex. 405 at 17-18 (Heinen Direct).

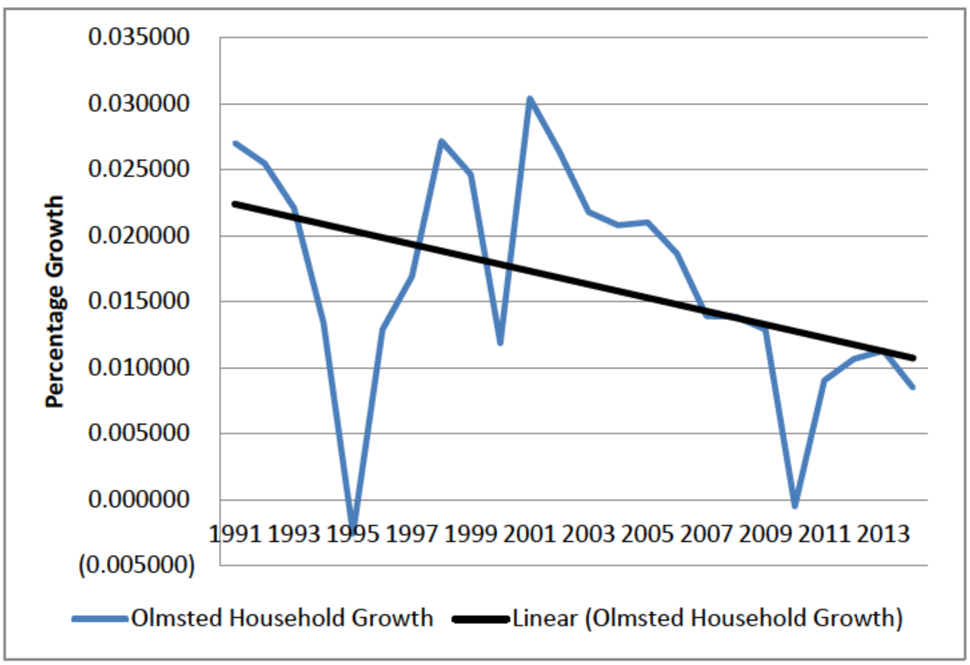
[16] Household data for the Rochester Area are available from the United States Census Bureau (Census Bureau) and Minnesota State Demographic Center (State Demographer), who collect (Footnote Continued on Next Page)

54. The Department used historical household data for Olmsted County Minnesota for 1970 to 2010 from the 2010 Census, and household data for 1990 to 2014 from the State Demographer to estimate historical household growth for the Rochester Area. DOC Ex. 405 at 16 and AJH-11 (Heinen Direct).

55. The Department compared these historical household counts to historical population numbers to determine whether a consistent relationship existed between households and population in the Rochester Area. The Department 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. DOC Ex. 405 at 16-17 (Heinen Direct).

56. The Department estimated the average annual household growth in the Rochester Area after 1990 to be approximately 1.65 percent; however, there has been a downward trend in household growth over this period. Household growth after 1990 is shown in Heinen Direct Graph 2 below. DOC Ex. 405 at 17 and AJH-11 (Heinen Direct).

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



DOC Ex. 405 at 17 (Heinen Direct).

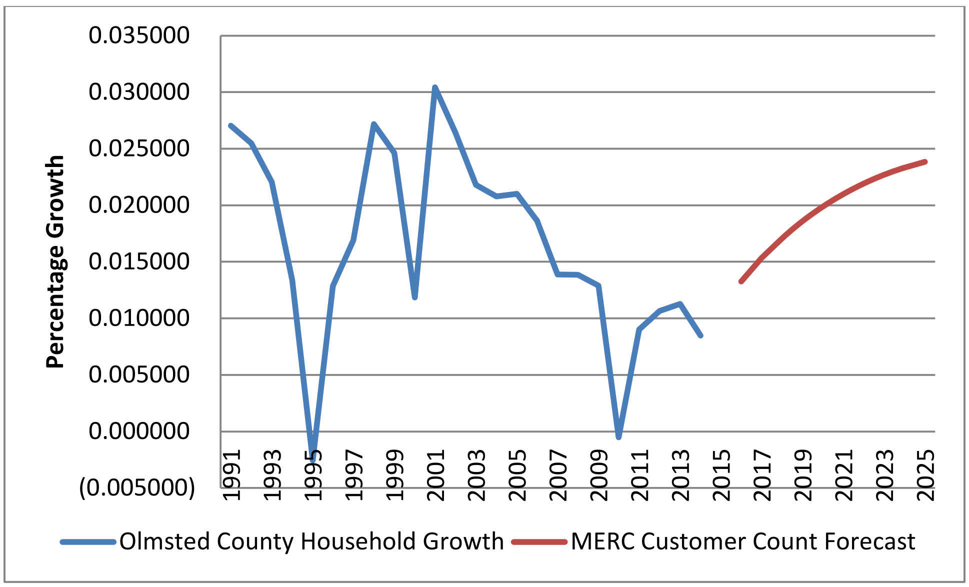
(Footnote Continued from Previous Page)
and publish household data on a decadal or annual basis and make it possible to analyze the appropriateness of the Company's forecasting results relative to other growth forecasts. DOC Ex. 405 at 16 and AJH-10 (Heinen Direct).

57. The Department also concluded that average household size has remained relatively constant at approximately 2.5 individuals per household since 1970. DOC Ex. 405 at 10 and AJH-18 (Heinen Direct).

58. This conclusion confirmed that it was reasonable for MERC to compare the RCOG's population growth estimates to the Company's customer count forecast shown in Graph 1 above. DOC Ex. 405 at 18 (Heinen Direct).

59. 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. 405 at 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. DOC Ex. 405 at 18 (Heinen Direct).

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



DOC Ex. 405 at 19 (Heinen Direct).[17]

60. The Department was concerned that the Company's expected growth rate was noticeably greater than the RCOG population growth rate, especially when considering that the RCOG's forecast likely assumed implementation of the DMC. The Department observed that the current trend in household growth had been fairly long lasting, nearly 10 years,

[17] In its Direct Testimony, the Department considered the Company's over-forecasting in this regard to be a temporary placeholder, the Department having observed that there may be a need for increased use of firm natural gas by RPU to produce electricity, where the RPU Infrastructure Report placed significant emphasis on the importance of natural gas for electric generation, and the potential replacement of existing generating facilities in the Rochester Area.

during a period of economic growth in the region,[18] and the overall success of the DMC and its implementation was unclear. This information meant that, if the DMC did not come to fruition, was implemented slower or in a manner different than MERC envisioned, it is likely that MERC customer growth for the region would be lower than MERC had forecasted. DOC Ex. 405 at 19-20 (Heinen Direct).

61. Given the burden of proof being on MERC to demonstrate the need for the Project and explain this assumed increase, the Department recommended that MERC address this issue in its Rebuttal Testimony, and concluded that MERC's projections represented the higher range of expected growth for the Rochester Area.

b. The Department Could Not Conclude that MERC's Reserve Margin Analysis Was Representative of Expected Conditions during the Forecasting Period.

62. The second area of potential concern was the Company's choice to use the growth rate from its sales forecast as the growth factor in its peak demand analysis. This choice presumed that changes in peak day usage, and expected changes in peak day usage, were the same or comparable to sales growth. DOC Ex. 405 at 20-21 (Heinen Direct).

63. The Company failed to provide data, however, that confirmed that peak day usage and sales growth exhibited a reasonably similar trend. 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. DOC Ex. 405 at 21 (Heinen Direct) (*citing* MERC Ex. 12 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. DOC Ex. 405 at 21 (Heinen Direct). Further, the Company provided no discussion of why it believed that the two analyses were comparable.[19]

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[18] 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. 9 at 10-13 (Clabots Direct).

[19] MERC did identify data issues that MERC had regarding older data. In prior MERC rate case filings, the Department and other state agencies had raised concerns regarding the appropriateness and validity of older data collected by MERC's predecessor. To address these concerns, MERC agreed to use only data generated after January 2007. DOC Ex. 405 at 21 (Heinen Direct) (*citing* MERC Ex. 9 at 5 (Clabots Direct). Because the Company's all-time peak day (101 AHDD) had occurred in 1996, MERC lacked data to estimate firm throughput from that peak day. In addition, MERC lacked firm-specific, daily data prior to the 2012 heating season because telemetry was not required of interruptible customers before this time. For these reasons, it appeared that MERC treated changes in peak day usage as being the same or comparable to sales growth because it lacked peak day data, and the only ready means to estimate peak day growth was to use the results of the sales forecast. DOC Ex. 405 at 21 (Heinen Direct).

64. In light of this lack of information, Department Witness Mr. Heinen attempted to examine past regulatory filings to confirm whether the Company's assumed 1.5 percent design-day growth assumption was reasonable. This analysis was complicated by the consolidation of MERC PGAs in July 2013, but he nevertheless examined historical MERC design-day filings to validate the Company's growth assumption. DOC Ex. 405 at 22 and AJH-12 (Heinen Direct).

65. 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 after 2010, the growth in the design-day had decreased on an annual basis. That is, prior to 2010, it appeared that MERC's system exhibited relatively consistent design-day growth, but in more recent time, the growth rates had moderated and become more volatile. Based on the recent design-day growth trends, it appeared that a growth figure closer to 1.0 percent was more appropriate. DOC Ex. 405 at 22 (Heinen Direct).

66. In summary, the Department concluded, as to this concern about the reserve margin, that the Company had failed to provide evidence to establish the reasonableness of its design-day growth figure, and without a reasonable estimate of design-day growth, the Department was unable to conclude that MERC's reserve margin analysis was representative of expected conditions during the forecasting period. DOC Ex. 405 at 22 (Heinen Direct) (*citing* MERC Ex. 12 at 25 (Mead Direct).[20]

c. The Base Peak Consumption Used by MERC to Establish Need Was Not Unreasonable.

67. The third issue with MERC's proposal was the presence of two separate peak demand forecasts.

68. As noted above, MERC conducted a peak demand forecast in its annual demand entitlement filings and in this proceeding. Although the Company did not conduct a long-range peak demand forecast in its annual demand entitlement filing, the peak demand analysis it conducted in the demand entitlement filing was analogous to the base forecast MERC estimated in this 15-895 docket, as both analyses had forecasts for the Rochester area.[21]

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[20] Further, because of these shortcomings in MERC's analysis, the Department conducted its alternative reasonable margin analysis (DOC Ex. 405 at 22 (Heinen Direct)) which is discussed below.

[21] The demand entitlement filings determined the appropriate capacity to serve demand on a peak day for a given PGA area, one of which was the Rochester Area. That is, the forecast in this proceeding is limited to the Rochester Area, and in its demand entitlement filing, MERC used separate regression models, by area, to determine peak demand for the NNG PGA area, and one of those areas was the Rochester Area. DOC Ex. 405 at 23 and AJH-6 (Heinen Direct).

69. The presence of two peak demands being produced by the Company raised the question of which forecast was most appropriate for determining need in this proceeding. DOC Ex. 405 at 23 and AJH-6 (Heinen Direct).

70. The Department examined the Rochester Area regression model in the demand entitlement filing and confirmed that in the peak day planning objective of 101 AHDD, the same regression adjustments were used, and the input data was the same in the two analyses. Because of this similarity, it was possible to compare the expected results associated with the two analyses. DOC Ex. 405 at 23 (Heinen Direct).

71. The Department concluded that the results of the two forecasts were not the same because the analysis MERC used to determine need in this 15-895 docket has different independent factors than the Rochester Area regression analysis MERC used in its 2015 demand entitlement filing. DOC Ex. 405 at 23-24 (Heinen Direct).

72. The demand entitlement forecast appeared to be approximately 16,800 Dkt/day greater than the Company's projected peak demand forecast in this docket. Specifically, inclusive of regression adjustments, MERC's projected peak demand in the demand entitlement filing was 106,050 Dkt/day, and in this proceeding, projected peak demand was 89,251 Dkt/day. DOC Ex. 405 at 24, AJH-6, and AJH-7 (Heinen Direct).

73. Thus, the Department concluded that MERC's forecasted need in this 15-895 case was not oversized. DOC Ex. 405 at 24 (Heinen Direct).

74. Nonetheless, to address the problem of MERC producing two peak demands, the Department attempted to independently verify base peak demand. The Department's analysis[22] resulted in a base peak consumption of approximately 90,000 Dkt/day, which was comparable to the estimate filed by the Company in this 15-895 docket. DOC Ex. 405 at 25 and AJH-13 (Heinen Direct).

75. Despite the fact that MERC estimated two peak days, the result of the Department's independent estimation confirmed that the base peak consumption used by MERC to establish need for this Project was not unreasonable. DOC Ex. 405 at 25 (Heinen Direct).

C. The Department's Alternative Analysis of Need Showed that the Size of MERC's Proposed Project Was Reasonable.

76. Customer counts are very important when determining need for this Project for two reasons. First, the methodology used by MERC underscored the importance of customer

[22] The Department used OLS regression to conduct a peak demand analysis using data over the period from January 2007 to February 2015. The Department's 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 was adjusted to remove non-firm usage. DOC Ex. 405 at 24-25 and AJH-13 (Heinen Direct).

counts in the forecasting period.[23] Second, firm consumption on a design-day or peak day, on a per-customer basis, had been trending downward over time, which meant the only factor driving the need for increased capacity was customer growth. DOC Ex. 405 at 25 (Heinen Direct).

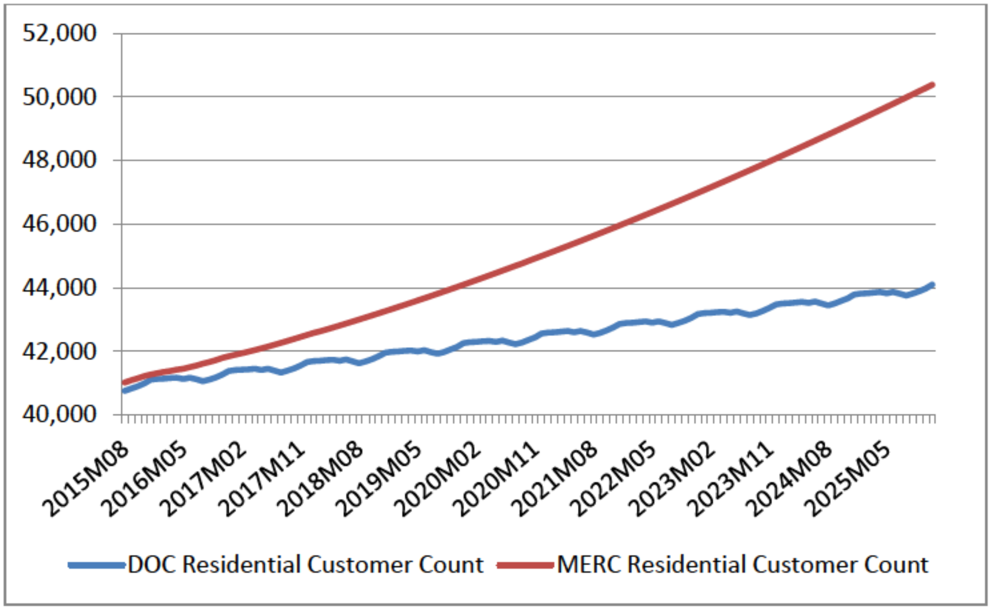
77. As noted above, the customer count forecast used by MERC in its need forecast may have been too high. Because of this concern, the Department performed its own analysis of need and specifically investigated customer growth in great detail by conducting its own alternative customer count forecast.[24] DOC Ex. 405 at 24-25 and AJH-14 (Heinen Direct).

78. The 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 projection of a 1.89 percent increase in a retail customer counts. The difference between the forecasts is shown in Heinen Direct Graph 4. DOC Ex. 405 at 27 (Heinen Direct).

[23] The customer count forecast was important in MERC's methodology. The Company's methodology used the estimated growth rate from its sales forecast to show increased demand consumption during the forecasting period. When forecasting sales or use per customer, the market standard is to assume normal weather during the forecasting period. In other words, weather is held constant in the forecasting period so that sales are approximated based on normal, or non-extreme, weather conditions. MERC employed a normal weather methodology. The Company's normal weather assumption resulted in constant use per customer in the forecasting period. DOC Ex. 405 at 26 (Heinen Direct) (*citing* MERC Ex. 3 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, the size of the proposed Project could be overstated. DOC Ex. 405 at 26 (Heinen Direct).

[24] The Department conducted its alternative customer count forecast using OLS regression analysis to forecast firm customer counts in the Rochester Area. The Department's analysis used monthly factors for January 2007 to July 2015 and autoregressive terms to forecast Rochester Area customer counts from August 2015 through December 2025. DOC Ex. 405 at 24 and AJH-14 (Heinen Direct).

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



DOC Ex. 405 at 27 (Heinen Direct).

79. The results of the Department's and MERC's customer count forecasts differed because the Department's forecast was based solely on historical MERC operations and included a single autoregressive term, while MERC's forecast included several different autoregressive terms and a trend factor. Because the Company's trend factor had a positive value, it is possible that the trend factor put unnecessary upward bias on customer count growth. DOC Ex. 405at 27 (Heinen Direct).

80. The Department's customer counts were reasonable although they did not factor in the DMC as a potential growth factor because it remains unclear when, or to what level, the DMC or other developments may impact future growth in the Rochester Area. The results of the Department's forecast were rooted firmly in current trends for the Rochester Area since January 2007, and were supported by the average historical customer growth in the Rochester Area as presented by MERC and the recent household growth figures for the Rochester Area. DOC Ex. 405 at 28 and AJH-11 (Heinen Direct) (citing MERC Ex. 9 at 10 (Clabots Direct)).

81. The Department concluded, and the ALJ agrees, that a comparison of MERC's and the Department's customer count forecast shows that each are potentially acceptable.

82. If the DMC is implemented as planned or there is a greater need for natural gas to produce electricity, then MERC's growth forecast are more likely to occur, but if the DMC is delayed or does not materialize and there is no greater need for natural gas to produce electricity, the Department's growth forecast is more likely to occur. The Department concluded that its forecast is a "status quo" forecast or a lower bound

projection, while MERC's projected growth represents an optimistic or upper bound forecast.

83. This conclusion is 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. DOC Ex. 405 at 28-29 (Heinen Direct) (*citing* MERC Ex. 9 at DWC-2, p. 7 of 14 (Clabots Direct)).

84. Because the Department's forecast likely represented the lower bound for reasonable growth, the Department conducted additional analysis to determine whether the proposed Project was reasonable, based on its forecast.[25] DOC Ex. 405 at 29 (Heinen Direct).

85. After estimating peak demand for the forecasting period, the Department re-created MERC's reserve margin analysis to assess the impact that the Department's lower growth rate would have on the Rochester Area and the MERC-NNG system reserve margins. DOC Ex. 405 at 29 (Heinen Direct) (*citing* MERC Ex. 12 at 25 (Mead Direct)).

86. In doing so, the Department modified MERC's reserve margin analysis, because it did not appear that MERC's assumption of 1.5 percent design-day growth was reasonable. The recent demand entitlement filings for the MERC-NNG and MERC-Northern Natural Gas PGA showed that recent trends in design-day growth were less than 1.5 percent on an annual basis and a 1.0 percent design-day growth rate was more reasonable. DOC Ex. 405 at 29-30 and AJH-12 (Heinen Direct).

87. The results of the Department's reserve margin analysis and calculations[26] in its Direct Testimony were summarized in Heinen Direct Table 1:

[25] The Department applied its customer count forecast results to the Company's UPC results to estimate future sales, and used the result to estimate firm growth in the forecast period. Specifically, the Department used a growth figure of approximately 0.77 percent to estimate increased growth in MERC'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. 405 at AJH-15 (Heinen Direct).

[26] The Department's reserve margin analysis and calculations filed in its Direct Testimony are shown in DOC Ex. 405 at AJH-16 (Heinen Direct).

Heinen Direct 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

DOC Ex. 405 at 30 (Heinen Direct).

88. The Department's reserve margin analysis in its Direct Testimony showed that its updated growth assumptions resulted 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 MERC in its Direct Testimony. MERC Ex. 12 at 25 (Mead Direct).

89. Instead of the excess capacity from the Project being used in approximately 2030, as were calculated by MERC, the Department's analysis showed that some level of excess capacity would exist until the end of the forecasting period in 2040. DOC Ex. 405 at 31 (Heinen Direct).

90. The Department estimated the costs associated with this estimated excess capacity. Using the estimated annual capacity costs provided in MERC's initial filing (MERC Ex. 1 at 102 (Initial Filing)) the Department's Direct Testimony calculated the costs of excess

capacity on an annual and total basis, as shown in Heinen Direct Table 2.[27] DOC Ex. 405 at 31 (Heinen Direct).

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

DOC Ex. 405 at 32 (Heinen Direct).

91. Heinen Direct Table 2 shows the excess capacity cost associated with the Department's forecast in Direct Testimony to be approximately $30 million greater, through 2040, than MERC's filed forecast. DOC Ex. 405 at 32 (Heinen Direct).

92. Assessing this excess capacity cost, Mr. Heinen stated that, because this "low growth" scenario showed excess capacity in the forecasting period, a smaller project and an incremental approach to adding capacity in the future could potentially satisfy the proposed need; however, he observed, it would only do so only at a risk of significant additional cost to MERC ratepayers.

[27] The supporting calculations are shown in DOC Ex. 405 at AJH-16 (Heinen Direct).

93. He explained that the construction of a smaller project included the risk that growth would be higher than the “low growth” scenario, in which case future expansions of capacity would likely be required. To address this possibility, Mr. Heinen conducted two reserve margin analyses that assumed the addition of 25,000 or 35,000 Dkt/day of incremental capacity to Rochester. These results[28] are summarized in Heinen Direct Tables 3 and 4:

Heinen Direct 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

DOC Ex. 405 at 33 (Heinen Direct).

[28] These results are filed as DOC Ex. 405 at AJH-17 and AJH-18 (Heinen Direct).

Heinen Direct 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

DOC Ex. 405 at 34 (Heinen Direct).

94. Mr. Heinen concluded that these incremental capacity additions would result in smaller amounts of excess capacity and associated revenues to be recovered from ratepayers. DOC Ex. 405 at AJH-17 and AJH-18 (Heinen Direct).

95. He noted, however, that these incremental alternatives were only viable under lower growth scenarios; he cautioned that if growth in the Rochester Area were closer to MERC's forecast, if overall system peak demand grew at MERC's forecasted rate, if the base peak demand in the Company's demand entitlement filing was more representative of peak demand, or, importantly, if increased natural gas were needed by RPU or any other electric utility, then the Company would be required to purchase additional capacity and, likely, to invest in additional upgrades to serve customers in the Rochester Area. DOC Ex. 405 at 34-35 (Heinen Direct).

96. In that scenario, the total cost associated with an incremental approach to adding capacity, or future capacity upgrades, would likely result in higher total costs to ratepayers than the Project as proposed. In addition, MERC noted that limiting

expansion capacity to 30,000 Dkt/day instead of the proposed 45,000 Dkt/day would result in a Net Present Value at $1 million *higher* than the proposed costs of the proposed project. DOC Ex. 405 at AJH-19 (Heinen Direct) (MERC Supplemental Response to DOC Information Request (IR) No. 37).

97. The Department concluded, in light of this analysis, that it is reasonable to assume that having to pursue a future upgrade to serve Rochester Area customers would result in additional, significant costs to MERC ratepayers. DOC Ex. 405 at 35 (Heinen Direct).

98. Turning to whether the excess capacity costs associated with these various scenarios was significant or unreasonable, Mr. Heinen explained that, while the excess capacity costs appeared large, especially the approximately $65 million amount over the 22 year period associated with the Department's preferred or base growth scenario, it is important to put these costs into the context of annual demand and commodity costs.

99. 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.[29] DOC Ex. 405 at 35-36 (Heinen Direct).

100. An additional useful comparison is that 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. 405 at 36 and AJH-20 (Heinen Direct).

101. The average costs of the Bison Contract for Residential customers is $38.09 per year, while *total* capacity costs for the Rochester Project would be $32.16 per year for Residential customers. DOC Ex. 405 at AJH-21 (Heinen Direct) (MERC Response to DOC IR No. 36).

102. The excess capacity costs are embedded in that $32.16, 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. DOC Ex. 405 at 36 (Heinen Direct).

103. In summary, based on this reserve margin analysis and its analysis of incremental capacity alternatives, the Department concluded in its Direct Testimony that the size of MERC's proposed Project was reasonable. DOC Ex. 405 at 36 (Heinen Direct); DOC Ex. 406 at 1-3 (Heinen Rebuttal).

104. Although smaller alternatives may be able to meet need in the Rochester Area, that outcome would only be possible if growth in the Rochester Area and on the MERC

[29] 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.

system as a whole, remained relatively constant despite known upward pressure on throughput, such as from the DMC.

105. If growth increased, there is a tangible risk that ratepayers would be required to invest in significant future upgrades that could have costs similar to or greater than the costs to the Project as proposed by MERC.

106. Further, any excess costs associated with the Project as proposed by MERC are relatively small on an annual basis and are comparable to insurance against the potential costs of future system upgrades.

107. And, finally, there are methods by which MERC could mitigate the costs of excess capacity going forward as are discussed below. DOC Ex. 405 at 36-37 (Heinen Direct).

D. The Department's Surrebuttal Updated Excess Capacity Analysis Reflects a Significant Decrease in Excess Capacity Costs to Ratepayers.

1. Overview

108. The Department in its Surrebuttal Testimony updated its excess capacity analysis (DOC Ex. 407 at 16 (Heinen Surrebuttal)) and modified its recommendation regarding need, based on the Rebuttal Testimony of OAG Witness Dr. Urban, which included correspondence with representatives from RPU regarding RPU's current and future natural gas usage. OAG Ex. 309/310 at JAU-R-2 (Urban Rebuttal Schedules).

109. After reviewing this attachment, the Department modified its recommendation to conclude that expected usage by RPU, coupled with the fact that MERC had acquired 100 percent of incremental capacity in the Rochester Area, will likely result in a diminution of excess capacity related to the proposed Project. DOC Ex. 407 at 16 (Heinen Surrebuttal).

2. The Department's Updated Excess Capacity Analysis

110. In its correspondence, RPU discussed three of its generation needs planned to occur between 2018 and 2031 that will use natural gas:

   a. Westside Energy Station in 2018 with an estimated consumption of 394,000 Mcf per year,
   b. A Combined Heat and Power unit in 2026 with an estimated consumption of 2,190,000 Mcf per year, and
   c. A Combined Cycle generation unit in 2031 with an estimated consumption of 4,730,400 Mcf per year.

DOC Ex. 407 at 16-17 (Heinen Surrebuttal) (*citing* OAG Ex. 309/310 at JAU-R-2 (Urban Rebuttal Schedules)).

111. Mr. Heinen's Surrebuttal explained that, even if RPU elects to take only transportation service, it is highly likely that these plants will be served with the excess capacity associated with the Rochester Project. DOC Ex. 407 at 17 (Heinen Surrebuttal). In addition, the RPU correspondence stated that there are numerous times each winter when

gas supply has been insufficient to operate RPU's Cascade Creek plant at full capacity. DOC Ex. 407 at 17 (Heinen Surrebuttal) (*citing* OAG Ex. 309/310 at JAU-R-2 (Urban Rebuttal)).

112. The system upgrades and excess capacity associated with the proposed Project will likely: decrease the number of curtailments in the Rochester Area, reduce the times when Cascade Creek cannot be operated at full capacity, and increase the annual consumption of natural gas by Cascade Creek. DOC Ex. 407 at 17 (Heinen Surrebuttal).

113. While it is unclear exactly how much this increased consumption would reduce MERC's excess capacity related to the proposed Project, there clearly would be a reduction in excess capacity. DOC Ex. 407 at 17 (Heinen Surrebuttal).

114. Using his prior assumptions and analysis (DOC Ex. 405 at AJH-16 (Heinen Direct)) and an estimated average daily consumption for each RPU generation facility identified in OAG Ex. 309/310 at JAU-R-2 (Urban Rebuttal Schedules), the Department provided updated results, as shown in Heinen Surrebuttal Table S-2.[30]

[30] The associated calculations are in the evidentiary record as DOC Ex. 407 at 17 and AJH-S-1 (Heinen Surrebuttal).

Heinen Surrebuttal Table S-2: Updated Comparison of Excess Capacity

Year	MERC Excess Capacity (Dkt/day)	DOC Excess Capacity (Dkt/day) (Preferred Case)
2019	29,017	30,886
2020	27,964	30,491
2021	25,413	28,615
2022	22,824	26,719
2023	20,196	24,802
2024	17,528	22,864
2025	14,821	20,905
2026	12,073	18,926
2027	9,204	16,924
2028	4,870	14,901
2029	472	12,857
2030		10,790
2031		8,701
2032		6,589
2033		4,454
2034		2,297
2035		
2036		
2037		
2038		
2039		
2040		

DOC Ex. 407 at 18 (Heinen Surrebuttal).

115. The Department concluded from this updated analysis that the addition of natural gas fired generation by RPU was likely to appreciably decrease MERC's excess capacity. DOC Ex. 407 at 18 (Heinen Surrebuttal).

116. Table S-2 indicates that in the Department's preferred analysis, the estimated level of excess capacity would decrease by 10,000 to 20,000 Dkt/day in the early part of the next decade and the duration of excess capacity would decrease significantly, from being expected throughout the forecasting period, to there being no excess capacity after 2034. DOC Ex. 407 at 18 (Heinen Surrebuttal) (*citing* DOC Ex. 405 at 30 (Heinen Direct)).

117. Further, assuming MERC negotiates maximum rates for capacity release (a reasonable assumption since MERC acquired 100 percent of incremental capacity in the Rochester Area), the Department's Surrebuttal updated its calculation of the cost of excess capacity in Heinen Surrebuttal Table S-3.

Heinen Surrebuttal Table S-3: Updated 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	$5,644,228	$6,300,355
2021	$5,112,325	$5,938,101
2022	$4,559,180	$5,552,642
2023	$4,008,553	$5,170,440
2024	$3,445,534	$4,770,757
2025	$2,913,606	$4,413,485
2026	$1,639,832	$3,308,958
2027	$1,108,287	$2,947,515
2028	$577,725	$2,578,910
2029	$55,628	$2,235,404
2030	$0	$1,885,667
2031	$0	$1,013,593
2032	$0	$767,585
2033	$0	$518,920
2034	$0	$267,571
2035	$0	$0
2036	$0	$0
2037	$0	$0
2038	$0	$0
2039	$0	$0
2040	$0	$0
Total	$31,257,522	$50,003,801

DOC Ex. 407 at 19 (Heinen Surrebuttal).

3. Summary

118. In summary, the Department's Direct Testimony had calculated excess capacity costs through 2040 of approximately $36 million for the Company's forecast and approximately $65 million for the Department's revised forecast (DOC Ex. 405 at 32 (Heinen Direct)), while the updated excess capacity costs shown in Heinen Surrebuttal Table S-3 represent a potential decrease in costs of nearly $5 million for MERC's forecast and nearly $15 million for the Department's preferred forecast. DOC Ex. 407 at 119-20 (Heinen Surrebuttal).

119. These estimated reductions reflect a significant diminution of costs to ratepayers. The reductions also highlight why it is important for ratepayers that MERC vigorously negotiate in the capacity release market.[31] DOC Ex. 407 at 20 (Heinen Surrebuttal).

E. Office of Attorney General's (OAG's) Concerns Regarding MERC's Need Analysis

1. Overview

120. Dr. Urban correctly observed concerns and deficiencies in MERC's need analysis; the Department's Direct Testimony shared these same concerns. DOC Ex. 405 at 1-11 (Heinen Direct).

121. Mr. Heinen, for example, agreed with Dr. Urban's observation that there is "considerable fluctuation in the annual percentage change in firm demand since 2007."[32]

122. The Department disagreed, however, that these concerns warrant a conclusion that the Company's proposed Project should not be approved. The results of the Company's analysis were not significantly different than the results of the Department's alternative analysis of need. DOC Ex. 407 at 4 (Heinen Surrebuttal).

123. The Department provided an alternative need analysis, reasonably based on certain reasonable assumptions (*e.g.*, design-day growth, customer growth) that were modified from the Company's initial analysis.

124. Based on that alternative analysis, the Department concluded that MERC's need analysis likely represents an optimistic view of expected growth in the Rochester Area, while the Department's need analysis likely represents a "status quo" view to growth in the Rochester Area.

125. Based on the potential risks and cost considerations of a building a smaller project, it remains the Department's conclusion that the Project, as proposed, is reasonable. DOC Ex. 407 at 4 (Heinen Surrebuttal).

2. Description of OAG's Concerns

126. Dr. Urban provided extensive discussion regarding Mr. Heinen's analysis of MERC's need analysis for its proposed Project. Dr. Urban noted areas of agreement but ultimately concluded that the Department's recommendation to approve the Project was incorrect and that the issues Mr. Heinen observed in the Company's analysis were such that the Project, as proposed, was unreasonable. Dr. Urban provided analysis regarding the

[31] Negotiation of sales into the capacity release market is discussed below.

[32] The existence of fluctuations in the annual percentage change in firm demand demonstrates that it is critical for MERC to be able to provide natural gas service even during unusually cold winter periods such as those recently experienced during the "polar vortexes" of 2014. DOC Ex. 407 at 3 (Heinen Surrebuttal).

Department's conclusions about the costs of the Project, and regarding a smaller, incremental approach to capacity expansion. DOC Ex. 407 at 2 (Heinen Surrebuttal).

127. Dr. Urban concluded that the Project was unreasonable because MERC's forecasted growth of 1.5 percent per year due to the expansion of the Mayo Clinic is too high "and there is not historical basis for the forecast result" given her calculation that actual sales growth in Rochester for the period 2007-2015, not adjusted for weather, had averaged out to be 0.00204 percent. DOC Ex. 407 at 2 (Heinen Surrebuttal) (*citing* OAG Ex. 307 at 3 (Urban Rebuttal)).

3. Response to OAG Concerns

128. Dr. Urban's calculation of the average percentage change in non-weather-normalized sales for the period 2007 to 2015 appeared to be based on an error in calculation. Correcting this error results in a larger growth over time in expected natural gas use in Rochester. DOC Ex. 410 at 2 (Heinen Summary).

129. Using the percentage changes in Dr. Urban's Rebuttal Table 1, reproduced in Heinen Table S-1 below, the average annual percentage change in actual sales for this period was 1.2 percent. Thus, this metric actually supports the conclusion that there is an historical basis for the forecast result. DOC Ex. 407 at 2-3 (Heinen Surrebuttal).

Heinen Table S-1: Average Percentage Changes in Actual Sales, 2007 - 2015

Years	**Percentage Change**
2007 - 2008	10.10%
2008 - 2009	-5.30%
2009 - 2010	-4.40%
2010 - 2011	4.80%
2011 - 2012	-16.40%
2012 - 2013	33.50%
2013 - 2014	11.70%
2014 - 2015	-24.40%
Average	**1.20%**

DOC Ex. 407 at 3 (Heinen Surrebuttal).

130. Dr. Urban provided a comparison of cost between the OAG's preferred smaller project and the Project as proposed by MERC. In support of a smaller, incremental project, Dr. Urban said that when excess capacity costs associated with the proposed Project are considered, costs associated with a smaller project, relative to the proposed Project, are significantly less. DOC Ex. 407 at 2 (Heinen Surrebuttal) (*citing* OAG Ex. 307 at 10-11 (Urban Rebuttal)). In other words, Dr. Urban concluded that the total cost (*i.e.,* project plus capacity cost) of the smaller, incremental project would be lower than the proposed Project. DOC Ex. 407 at 4 (Heinen Surrebuttal).

131. The Department agreed that, if there is low sales growth in Rochester, a smaller project may appear to be better for ratepayers. However, the risk of much higher costs exists if growth related to the DMC and Rochester Public Utilities materializes. DOC Ex. 405 at 34-37 (Heinen Direct); DOC Ex. 407 at 5-6 (Heinen Surrebuttal).

132. Although it is not fully quantifiable, it is important to consider these factors involved with building a smaller project, and these factors were omitted from Dr. Urban's analysis. It is unreasonable to fail to consider risks that would likely represent a significant increase in costs for MERC's ratepayers, given the expectation that MERC will provide reliable service. DOC Ex. 407 at 6 (Heinen Surrebuttal).

133. Finally, Dr. Urban's Rebuttal Testimony implied that the Department found MERC's need forecast unreasonable. OAG Ex. 307 at 17 (Urban Rebuttal). This is inaccurate. The Department identified issues and concerns with MERC's need analysis, but did not conclude that the results of the need analysis were unreasonable. The results of the Company's need analysis likely represent an optimistic, or high growth, scenario. DOC Ex. 407 at 6 (Heinen Surrebuttal) (*citing* DOC Ex. 405 at 28 (Heinen Direct)).

134. In integrated resource plans (IRP) and certificate of need (CN) filings, the forecast or need analyses typically include low-growth, base growth, and high-growth scenarios. Generally, any of these forecasts, or results in between, are considered acceptable with the base case being the most likely scenario. Using this comparison as a guide, the Department concluded that the Company's need projections are not unreasonable and likely represent an acceptable estimate of expected need for the Rochester Area. DOC Ex. 407 at 6 (Heinen Surrebuttal).

F. Summary

135. The Department recommended, and the ALJ agrees that the Commission should find 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. DOC Ex. 405 at 58-59 (Heinen Direct).

136. The Department recommended, and the ALJ agrees, that the Commission should find that the Company's need projections are not unreasonable and likely represent an acceptable estimate of expected need for the Rochester Area. DOC Ex. 405 at 36 (Heinen Direct); DOC Ex. 406 at 1-3 (Heinen Rebuttal); DOC Ex. 407 at 6 (Heinen Surrebuttal).

4. THE PROJECT IS ELIGIBLE FOR COST RECOVERY THROUGH THE NATURAL GAS EXTENSION PROJECT (NGEP) RIDER.

A. Overview of Party Positions Regarding Eligibility for NGEP Rider Treatment

137. The Parties do not agree whether the Project is NGEP rider eligible.

138. The Department and Company believe that the Project is NGEP rider eligible and that Rochester and the surrounding area meet the definition in Minn. Stat. § 216B.1638 subd.

3[33] of an unserved or inadequately served area, as is required to be eligible for rider recovery under the NGEP Statute. DOC Ex. 410 at 3 (Heinen Summary).

139. The OAG disagrees that the Project meets the definition of the NGEP statute.

B. Department's Analysis

140. Rochester and the surrounding area meet the definition in Minn. Stat. § 216B.1638 (2016) of an "inadequately served area" (DOC Ex. 410 at 3 (Heinen Summary)), and the Rochester Project is NGEP rider eligible because the Rochester Area is capacity constrained (DOC Ex. 405 at 58-59 (Heinen Direct)) and is at increasing risk of an unreliable supply of firm natural gas.

141. MERC's Initial Filing demonstrated that in January of 2014, during the "Polar Vortex" event that struck the region, after interrupting its interruptible and transport customers, MERC exceeded its total firm contracted capacity at Rochester TBS 1D. MERC Ex. 1 at 2 (Initial Filing); *see also* MERC Ex. 12 at 6-7 (Mead Direct). The Department concuded that the Rochester area is "inadequately served" with respect to natural gas capacity.

142. Minn. Stat. § 216B.1638 subd. 3 (b) to (d) provides as follows:

> (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.

143. With respect to Minn. Stat. § 216B.1638 subd. 3 (b)(1), the Department concludes that the Project extends natural gas service to an unserved or inadequately served area. The Department's review of the Company's load data for Rochester and the TBSs in the surrounding area confirmed that firm usage is at or above currently deliverable entitlement levels. DOC Ex. 405 AJH-7 (Heinen Direct).

144. In addition, in light of the expected growth, even at a baseline level, it is unlikely that MERC will be able adequately to serve existing, or expected, end-use customers on a going-forward basis. DOC Ex. 405 at 38 (Heinen Direct).

[33] The "NGEP statute."

145. With respect to Minn. Stat. § 216B.1638 subd. 3 (b)(2), whether individual costs are reasonable or prudently incurred cannot be fully determined until actual costs occur. The costs provided in this record were estimates and actual costs will not be known 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. DOC Ex. 405 at 39 (Heinen Direct).

146. The Company provided an estimate of total Project costs that it anticipates being eligible for rider recovery. MERC estimated in its Direct Testimony 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 (that have 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. 5 at 15-16 (Lee Direct). DOC Ex. 405 at 39 (Heinen Direct).

147. 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 NGEP rider or via the Company's base rates and be charged to customers. The capacity costs related to the recovery of costs are associated with NNG's construction costs, which the pipeline will incur to facilitate the expansion of available capacity to the Rochester Area. These NNG-related costs are expected to be recovered through MERC's monthly PGA. DOC Ex. 405 at 39-40 (Heinen Direct).

C. OAG's Concerns Regarding Eligibility Under the NGEP Statute

148. The Office of Attorney General (OAG) proposed that the Rochester area is not "inadequately served" based on an analysis in which it suggests that the phrase, "inadequately served area" may be determined to be ambiguous and the NGEP statute inapplicable. The OAG offers a two-step process for finding the phrase "inadequately served area" to be ambiguous.

149. In the first step, OAG proposes that the ALJ find the statutory phrase "inadequately served area" to be synonymous with the phrase "underserved area." The OAG provides no citation to authority or any evidence or discussion to support this first step.

150. In the second step, OAG proposed that the ALJ adopt a definition of "underserved area" used in an article on natural gas line extensions[34] in which the author urges that "residential, business, agricultural, and industrial energy consumers … switch from oil, propane, and other fuels to natural gas." The article states that:

[34] Ken Costello, *Line Extensions for Natural Gas: Regulatory Considerations* at ii (Feb. 2013)(*Line Extensions*). Mr. Costello's article describes the author as a researcher at the National Regulatory Research Institute (NRRI) of Silver Spring Maryland. The article's publication pre-dates passage of the NGEP statute.

> Switching to natural gas also may have broader public benefits, such as a cleaner environment, more reliable service, and economic development. With natural gas prices presently far lower than oil and propane prices, large-scale switching to natural gas could create public benefits substantial enough to warrant governmental actions.… Overall, switching to natural gas has the potential to save energy consumers substantial sums of money and contribute to a cleaner and more robust economy.

Line Extensions at iv.

151. The *Line Extensions* article "focuses on fuel switching from oil and propane to natural gas that requires gas-line extensions" (*id.* at 2), and specifically promotes "grow[th of] gas usage in *underserved areas* that currently have gas mains." *Id.* at 1 (emphasis added).

152. For purposes of his analysis of fuel switching, the author of the *Line Extensions* article distinguishes unserved areas (which he defines as areas having no access to natural gas) from underserved areas, and defines the phrase "underserved area" as one that "may have main lines nearby but many households and businesses that consume other forms of energy." *Id.* at 3.

153. The *Line Extensions* article does not claim that the phrase "underserved area" is a technical term of art in the industry, or that it is anything other than a phrase coined for purposes of the article's discussion of issues surrounding the switching of customers to natural gas by means of gas-line extensions. There is nothing in the evidentiary record of this 15-895 docket that further illuminates the author's use of the term "underserved area" in the *Line Extensions* article.

154. There is no evidence in the record to suggest that the phrases, "underserved area" or "inadequately served area" are synonymous, or to support a conclusion that the NGEP statute's use of the phrase "inadequately served area," means an area that "may have main lines nearby but many households and businesses that consume other forms of energy."

155. There appears to be no basis to conclude that the *Line Extensions* article's use of the phrase "underserved area" should be deemed a technical term of art assigned the proposed special meaning.

156. The Department recommended that the phrase "inadequately served area" should be accorded its plain meaning.

157. When interpreting a statute, Minnesota courts first determine whether the statutory language is clear or ambiguous. *State v. Moua*, 874 N.W.2d 812, 816 (Minn. Ct. App. 2016). A statute's words and phrases are to be given their plain and ordinary meaning. Minn. Stat. § 645.16 (2016); *State v. Koenig*, 666 N.W.2d 366, 372 (Minn. 2003). Where a statute is unambiguous in its plain meaning, "the legislature's intent is 'clearly manifested by [the] plain and unambiguous language' of the statute," and further

statutory construction "is neither necessary nor permitted." *State by Beaulieu v. RSJ, Inc.*, 552 N.W.2d 695, 701 (Minn. 1996) (*quoting Ed Herman & Sons v. Russell*, 535 N.W.2d 803, 806 (Minn. 1995); *State v. Rick*, 835 N.W.2d 478, 482 (Minn. 2013) (citation omitted).

158. A statute is considered ambiguous only "if it is *reasonably* susceptible to more than one interpretation." *Current Tech. Concepts, Inc. v. Irie Enters., Inc.*, 530 N.W.2d 539, 543 (Minn. 1995) (emphasis added).

159. The ALJ finds the OAG's proposed two-step process for finding ambiguity based on a claimed special, technical meaning is not reasonable.

160. The NGEP Statute defines an "unserved or inadequately served area," as: "an area in this state lacking adequate natural gas pipeline infrastructure to meet the demand of *existing* or potential end use customers." Minn. Stat. § 216B.1638 subd.1(i). The phrase "inadequately served area," appears to mean, simply, an area that is *not* adequately[35] served by existing infrastructure, without regard to whether the customers are existing or potential new customers who switch from another fuel.

161. According the phrase "inadequately served area," its plain meaning is consistent with other Minnesota utility regulation laws, in which the terms "adequate" and "inadequate" abound, and are given their ordinary meaning. For example, Minn. Stat. § 216B.17 subd. 1 provides that, on its own motion or upon a complaint that service is *inadequate*, the Commission may make such investigation as it deems necessary. Minn. Stat. § 216B.01 declares it to be in the public interest that public utilities be regulated in order to provide the retail consumers of natural gas and electric service in this state with "*adequate* … services at reasonable rates." (emphasis added). Minn Stat. § 216B.04 requires public utilities to "furnish safe, *adequate,* efficient, and reasonable service." Minn. Stat. § 216B.23 subd. 2 authorizes the Commission to require that utilities provide reasonable service in lieu of service found to be unreasonable, *inadequate*, or otherwise unlawful. Minn. Stat. § 216B.098 subd. 2 requires utilities to provide *adequate* notice to customers. The terms "adequate" and "inadequate" are used no less than twenty-six times in Minn. Stats. Ch. 216B, where they appear to have their ordinary and plain meaning, and "inadequate" simply means "not adequate."

162. The OAG also argued that, if the phrase "inadequately served area" has its ordinary meaning, the law would be so broad as to apply to most natural gas utilities' projects, which, the OAG stated, would be an absurd or unreasonable result. OAG Initial Brief at

[35] "Inadequate" means:

- "not adequate to fulfill a need or meet a requirement; insufficient" *Amer. Heritage® Dictionary, 5th Ed*, *https://ahdictionary.com/word/search.html?q=inadequate;*
- "not adequate, insufficient, not capable", *www.merriam-webster.com/dictionary/inadequate;*
- "not enough, or not good enough for a particular purpose," *www.macmillandictionary.com/us/dictionary/american/inadequate.*

82. The OAG argued that it is necessary to construe the NGEP statute not to be unreasonable or absurd. *Id.* at 82-85.

163. The Department disagreed that such a result would be absurd. The use of riders to facilitate cost recovery—even large cost recoveries—between rate cases is not extraordinary, inherently unreasonable, or a substantial departure from past practice. Riders are frequently used in this way. For example, Minn. Stat. § 216B.1692 creates a special emissions reduction rider and Minn. Stat. § 216B.1695 authorizes use of that rider for recovery of investment in certain large projects that cost in excess of $10 million.

164. Furthermore, if the legislature had intended to limit use of the NGEP rider in the fashion proposed by the OAG—solely for line extensions to extend the utility's natural gas distribution plant to homes and businesses that are located near gas mains but burn oil, propane or other fuels—it could easily have said so. It did not. The NGEP statute makes no reference to an objective of replacing the use of other fuels with natural gas usage. The statute makes no reference to propane. It is not absurd or unreasonable to assign the phrase "inadequately served area," its ordinary meaning, where there is no indication in the record or the law that "inadequate service" refers exclusively to service that uses fuel other than natural gas.

165. In summary, the phrase "inadequately served area" in the NGEP statute should be given its plain meaning: an area that is not adequately served. Rochester and the surrounding area is an "inadequately served area" because it is capacity constrained (DOC Ex. 405 at 58-59 (Heinen Direct)) and is at increasing risk of an unreliable supply of firm natural gas. The Rochester Project is NGEP rider eligible.

D. The Department Recommended a Soft Cap on Rider Cost Recovery

166. The Department has a general goal or policy as it relates to cost caps for large utility projects. The Department has maintained that it is important to hold utilities accountable to their estimates of reasonable costs, so that ratepayers are not liable for unreasonable costs or cost overruns that have no limit.

167. 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.

168. However, providing some clarity on expected costs at when a project is being considered 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.

169. In 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 will have the burden of proof to show that costs above the approved level are prudent and why it is reasonable to recover such costs from ratepayers. DOC Ex. 405 at 30 (Heinen Direct).

170. It is important for the Commission to hold utilities accountable for large project costs because 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.

171. 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 would 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. DOC Ex. 405 at 41 (Heinen Direct).

172. 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 its jurisdiction accountable for their transmission CN cost estimates by capping in the utilities' riders at the amount approved for recovery from ratepayers through the TCR. Utilities may request recovery of cost overruns in subsequent rate cases in the same way that they always have been able to do, where the burden of proof remains on the utility to show why ratepayers should pay for such costs, but cost overruns are typically not allowed to be recovered in the extraordinary riders. DOC Ex. 405 at 41 (Heinen Direct).

173. There are many examples of decisions to limit recovery of cost overruns in riders. For example, in Xcel Energy's TCR Rider filing in Docket No. E002/M-09-1048, the Commission decided, in its April 7, 2010 Order regarding Xcel's recovery of transmission project costs on a going-forward basis in the Xcel Energy docket, as follows:

> …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.

DOC Ex. 405 at 41-42 (Heinen Direct).

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

> 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.

DOC Ex. 405 at 42-43 (Heinen Direct) (footnotes omitted).

175. Regarding potential cost caps for this project, the Department recommended that the Commission find that the appropriate cap for this project is $44,006,607, as detailed in MERC's Direct Testimony, MERC Ex. 5 at 16, Table 1 (Lee Direct), which includes a $7,341,321 contingency factor.[36] MERC Ex. 3 at Attachment D (Initial Filing).

176. In the event that costs are greater than this cap, it is the Company's burden to show that these additional costs are reasonable to be recovered from ratepayers. DOC Ex. 405 at 43 (Heinen Direct). Just as MERC bears the burden of proof in this docket, it will 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

[36] At the time of the Department's Direct Testimony, it was unclear if this contingency factor was reasonable or comparable to a similar project; and, for this reason, the Department's Direct recommended that the Company address this issue in its Rebuttal Testimony. In Rebuttal, MERC explained that this twenty percent was simply a standard contingency that MERC uses in capital cost estimates, and the same contingency level used in other recent projects. MERC Ex. 8 at 5-6 (Lyle Rebuttal); MERC Ex. 25 at 2 (Lyle Summary).

has included, or intends to include, certain costs in the rider that should not be included in the rider. In the event that this situation occurs, the Company would not be able to recover up to the cap level because certain costs were deemed to be unreasonable for rider recovery. DOC Ex. 405 at 43-44 (Heinen Direct).

177. A soft cap is reasonable because it would require MERC to justify recovery of any costs higher than this $44 million amount and, therefore, provides an incentive for the Company to reasonably manage costs, while providing MERC the ability to request and recover additional costs that the Commission finds to be reasonable. DOC Ex. 410 at 3 (Heinen Summary). Further, use of a soft cap aligns with how the Commission has addressed cost recovery in other rider and Certificate of Need filings.

178. Minn. Stat. § 216B.1638 subd. 3 (c) states that 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, MERC is compliant. MERC did not propose to recover greater than 33 percent of Project costs through the rider. MERC Ex. 5 at 17 (Lee Direct). DOC Ex. 405 at 44 (Heinen Direct).

179. With respect to Minn. Stat. § 216B.1638 subd. 3 (d), MERC provided discussion and illustrative numbers in its initial filing regarding its revenue deficiency associated with the proposed project. MERC Ex. 5 at 29-34 (Lee Direct). DOC Ex. 405 at 44 (Heinen Direct).

180. This filing does not represent the last time that parties, or the Commission, can raise questions regarding the reasonableness of certain costs. The Commission will have the opportunity to review costs in future rider reviews and in subsequent general rate cases.

181. 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. 405 at 44 and AJH-2 (Heinen Direct).

182. The NGEP Statute is clear that incremental costs associated directly with the Project are the only amount eligible for rider recovery. It was unclear from MERC Ex. 3 at Attachment D (Initial Filing) and MERC Ex. 5 at 18 (Lee Direct) whether the Company included any items, or categories, in its rider recovery that may be questionable.

183. In particular, the Company included line items for Operations and Maintenance (O&M) expenses, which can include total costs if not properly accounted for. MERC is at risk of cost disallowance if it includes unapproved costs in its rider recovery proposal. In addition, 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. DOC Ex. 405 at 45 (Heinen Direct).

184. The Department concluded, and the ALJ agrees, regarding the eligibility of MERC's proposed Project for rider recovery, that Rochester and the surrounding area meet the definition of an "unserved or inadequately served area" in the NGEP Statute.

185. The reasonableness or prudency of 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.

186. The Department stated that it will fully review costs in future filings and recommended 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. DOC Ex. 405 at 45-46 (Heinen Direct).

E. MERC's Concerns Regarding a Cost Cap Are Overstated or Incorrect.

187. The Company disputed the Department's recommendation that the Commission establish, for purposes of rider recovery, a soft cost cap for this Project of $44,006,607 which includes a 20 percent contingency factor, with which the Department does not take issue.)

188. MERC expressed concern that a soft cost cap would add risk to the Project and would not recognize the fact that a route has not been set for the Project. MERC Ex. 8 4-6 (Lyle Rebuttal). Regarding MERC's proposed 20 percent contingency factor, Ms. Lyle also stated that this level is a standard practice that its affiliates have used in other states. DOC Ex. 407 at 7 (Heinen Surrebuttal) (*citing* MERC Ex. 8 at 6 (Lyle Rebuttal).

189. MERC's concerns regarding the proposed soft cost cap are not accurate and are overstated. First, the Department's cost cap proposal is not a hard cap on costs; it can be best described as a soft cap. DOC Ex. 405 at 45-46 (Heinen Direct). In the event that costs are greater than the revenue figure proposed by the Company, MERC will have the ability to recover costs above the cap if it can justify the cost overruns. DOC Ex.405 at 43 (Heinen Direct); DOC Ex. 407 at 7 (Heinen Surrebuttal).

190. Second, the Company's argument regarding route uncertainty is unfounded. Although route uncertainty may impact costs; the Project did not require a certificate of need, so nothing preventing the Company from finalizing a route prior to approval of the Project, in which case MERC would have had a more definitive estimate of cost. Because the Company chose not to do so, MERC will need to document carefully the reasons for any cost increases. DOC Ex. 407 at 7-8 (Heinen Surrebuttal).

191. Third, as discussed above, soft costs caps in riders are an important tool that the Commission uses to hold utilities financially accountable and utilities have an opportunity to justify higher costs, should they occur. DOC Ex. 407 at 8 (Heinen Surrebuttal).

192. For example, the Commission agreed with the finding of the ALJ in a recent proceeding proposing to build the electric equivalent of this pipeline,

> The ALJ recommended that the Commission continue its practice of limiting cost recovery in riders to the costs put forward by an applicant in certificate of need proceedings. However, the ALJ also noted that the Commission has recognized that cost overruns can be prudently incurred,

> and should be fairly compensated, when a utility is faced with unanticipated complications during the routing proceeding.
>
> …
>
> The Commission concurs with the Administrative Law Judge and accepts her findings, conclusions, and recommendations regarding rejection of the hard cap cost recovery recommended by LPI. Instead, the Commission will impose the soft cap on cost recovery recommended by the ALJ, the Department, and the Company in these proceedings.
>
> The Commission also concurs with the ALJ and the parties that issues regarding the details of cost recovery are not directly relevant to the issue of need, and will be more appropriately addressed in a future rider or rate case proceeding. The Commission agrees, however, that it is reasonable to put Minnesota Power on notice about its future cost recovery options for the project.

In the Matter of the Request of Minnesota Power for a Certificate of Need for the Great Northern Transmission Line, (Docket No. E015/CN-12-1163) Order Granting Certificate of Need with Conditions (June 30, 2015) at 19. DOC Ex. 407 at 8 (Heinen Surrebuttal).

193. The Rebuttal Testimony of MERC Witness Ms. Lee reiterated MERC's disagreement with the Department's recommendations regarding a cap on Project costs; it incorrectly claimed that the Department's recommendation, that the Commission defer findings on the prudency of costs until actual costs are incurred, is inconsistent with the language of the Natural Gas Expansion Project (NGEP) Statute. MERC Ex. 6 at 26-29 (Lee Rebuttal).

194. Ms. Lee's argument appears to ignore the scope of analysis laid out by the Commission in its February 8, 2016 Order establishing a contested case in this matter, where the Commission stated that it 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. 405 at 44 and AJH-2 (Heinen Direct); DOC Ex. 407 at 2 (Heinen Surrebuttal).

195. Because the Commission's February 8, 2016 Order expressly deferred review of the incremental revenue deficiency until the Company seeks formal filing and approval of an NGEP rider in a future rider or rate case filing, it is clear that the Commission did not intend to determine the prudency or reasonableness of specific cost estimates at this time. DOC Ex. 407 at 14-15 (Heinen Surrebuttal); DOC Ex. 410 at 3 (Heinen Summary).

196. Further, the record in this proceeding does not support a conclusion as to the reasonableness of individual cost components. That decision should be deferred, as noted in the Commission's February 8, 2016 *Order*, until a later formal rider or rate case filing. DOC Ex. 407 at 15 (Heinen Surrebuttal).

F. OAG's Concerns Regarding a Cost Cap

197. The OAG appears to argue against a finding in this docket of reasonableness and prudency; it bases this argument, in part, on a concern that in a future proceeding, denial of any requested recovery may "be much more challenging." This concern is overstated. The procedure employed in this docket is the same employed in other similar dockets in which rider treatment is allowed by a specific statute.

198. In this docket, the prudency of the estimated expenses is to be evaluated, and in a subsequent proceeding the Commission will consider rate recovery, and in that proceeding, the Commission will determine whether the utility has met its burden to show the reasonableness of recovering particular costs from ratepayers.

199. This was the same process used in *In the Matter of Otter Tail Power Company's Request for Approval of its Environmental Upgrades Cost Recovery Rider for the Big Stone Plant*, Docket No. E-017/M-13-648. There, the project and particular costs were reviewed for prudency and reasonableness under a then-newly amended law, Minn. Stat. § 216B.1692 subd. 1(b). This review followed an earlier contested case proceeding in Docket No. E017/M-10-1082, which had been conducted consistent with Minn. Stat. § 216B.1695, in which the project and its *estimated* costs had received an "advance determination of prudence." In its Order dated December 18, 2013 in Docket 13-648, the Commission allowed rider recovery for only a portion of the company's requested recovery. Order at 1 (excluding rider recovery for a baghouse and activated carbon injection (ACI) system costing in excess of $40 million).

200. The Commission has tools with which it can assess the reasonableness of particular costs in a subsequent proceeding. A finding of prudency in this proceeding need not be colored by speculation that the Commission might inadequately conduct its future review of Rochester Project costs.

G. Summary

201. The Department recommended, and the ALJ concurs, that the Commission should find that the Project is NGEP rider eligible because the Rochester Areas meet the definition of Minn. Stat. § 216B.1638 of an unserved or inadequately served area eligible for rider recovery. DOC Ex. 405 at 59 (Heinen Direct); DOC Ex. 410 at 3 (Heinen Summary).

202. The Department recommended, and the ALJ concurs, that the Commission should establish, for purposes of rider recovery, a soft cost cap for this Project of $44,006,607[37] ((DOC Ex. 405 at 59 (Heinen Direct); DOC Ex. 410 at 3 (Heinen Summary); DOC Ex. 407 at 15 (Heinen Surrebuttal)) and find that the reasonableness and prudency of any costs in excess of $44,006,607 including the contingency factor can be considered when

[37] This figure is inclusive of a 20 percent contingency factor. DOC Ex. 410 at 3 (Heinen Summary).

MERC proposes to recover the costs in base rates. DOC Ex.405 at 43 (Heinen Direct); DOC Ex. 407 at 7 and 10 (Heinen Surrebuttal).

5. MERC Can Mitigate Cost Increases to Ratepayers for Increased Capacity Costs.

A. Overview

203. Although the Department concluded that the Project is reasonable, and the excess capacity costs are not significant, the Department also concluded that MERC should take all reasonable steps to mitigate cost increases where possible because capacity costs are typically recovered through the demand portion of the PGA and it would be expected that the Company's firm customers would pay for the costs of excess capacity. DOC Ex. 405 at 59 (Heinen Direct); DOC Ex. 410 at 6 (Heinen Summary).

204. Various methods exist to mitigate capacity costs for sales customers, including long-term capacity release contracts, assessment of the cost of capacity to interruptible customers, movement of customers to firm service, and potential sales of supplies to electric generation customers. DOC Ex. 405 at 59 (Heinen Direct); DOC Ex. 410 at 6 (Heinen Summary).

205. The Company agreed to explore the capacity release market and to review its tariff books to determine whether changes should be made to facilitate the movement of customers from interruptible to firm service. DOC Ex. 410 at 6 (Heinen Summary).

206. Because MERC has procured 100 percent of the incremental capacity associated with the Project in the Rochester Area, any party, including RPU, wishing to use additional capacity in the Rochester Area should be required to pay for the capacity costs associated with the Project. DOC Ex. 410 at 6-7 (Heinen Summary).

207. MERC should be proactive in finding potential purchasers of firm capacity from the electric industry as natural gas becomes a more attractive generation source. DOC Ex. 405 at 59-60 (Heinen Direct).

208. Calculations in the Heinen Surrebuttal indicate that MERC's procurement of excess capacity may reduce, or mitigate, excess capacity costs from between $5 million (under the Company's estimate) and $15 million (under the Department's preferred case estimate) through 2040. DOC Ex. 410 at 7 (Heinen Summary).

B. Department's Analysis of Mitigation of Increased Capacity Costs

209. MERC's proposal would recover any excess capacity costs associated with the Rochester Project from MERC-NNG ratepayers through the monthly PGA. DOC Ex. 405 at 46 (Heinen Direct).

210. If these capacity costs were flowed solely through the demand portion of the PGA, then the Company's firm ratepayers would 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. DOC Ex. 405 at 46 (Heinen Direct).

211. The Department explained that the excess capacity costs are not 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. DOC Ex. 405 at 46 (Heinen Direct).

212. Capacity release is the most likely means of mitigating cost. 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. DOC Ex. 405 at 47 (Heinen Direct).

213. MERC provided detailed information in its Response to DOC IR No. 26 regarding its historical capacity releases since January 2007. DOC Ex. 405 at AJH-23 (Heinen Direct). These data show that, on average, MERC has received approximately $625,000 in capacity release credits each year since 2007. DOC Ex. 405 at 47 (Heinen Direct).

214. 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. There is some relief to ratepayers but short-term capacity release is not a significant tool to mitigate costs. DOC Ex. 405 at 47 (Heinen Direct).

215. Longer-term capacity release agreements exist, however. Other Minnesota utilities have engaged in longer term capacity release contracts. These contracts 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. DOC Ex. 405 at 47-48 (Heinen Direct).

216. 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. DOC Ex. 405 at 48 (Heinen Direct).

217. In its Response to DOC IR No. 26, MERC agreed to consider longer term capacity release agreements on a case-by-case basis. DOC Ex. 405 at AJH-23 (Heinen Direct). DOC Ex. 405 at 48 (Heinen Direct).

218. At the evidentiary hearing, MERC stated that it agreed with the Department that "transport customers should be charged at a level that appropriately reflects the benefits they will receive as a result of the overall project" and that MERC "will make every effort to obtain the best available contract terms for release of excess capacity." 1 Tr. at 20.

219. In addition, there any other ways MERC can deal with this excess capacity and associated costs. 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 at the maximum rate. DOC Ex. 405 at AJH-26 (Heinen Direct).

220. The maximum rate is significantly higher than the negotiated rate; however, it is possible that paying the maximum rate for volumes above 20 percent may be cheaper than procuring additional entitlements to serve need in other parts of the MERC system. DOC Ex. 405 at 48 (Heinen Direct).

221. The Department anticipates that when additional capacity is needed in other parts of MERC's system, it will revisit this issue to determine whether MERC ratepayers received the lowest priced entitlements possible. DOC Ex. 405 at 48 (Heinen Direct).

C. MERC's Response to the Department's Analysis of Cost Mitigation

222. In its Rebuttal testimony MERC responded to concerns the OAG and Department raised on this issue and explained how interruptible and transportation customers would be impacted by the excess capacity associated with the proposed Project**.** DOC Ex. 407 at 15 (Heinen Surrebuttal) (*citing* MERC Ex. 6 at 39-44 (Lee Rebuttal)).

223. The Company admitted that the excess capacity associated with the Project, as proposed, would represent a rate design issue for the MERC system. DOC Ex. 407 at 15 (Heinen Surrebuttal).

224. MERC agreed that excess capacity in the Rochester Area would likely result in a decrease in curtailments and a drift to "firmer" capacity for these customers, and MERC noted that these customers would still bear a risk of curtailment. DOC Ex. 407 at 15 (Heinen Surrebuttal).

225. MERC stated that it will work with interruptible customers to transition them, when possible, to firm capacity but, MERC believes, its current tariff language restricts its ability to require customers to switch service. DOC Ex. 407 at 15 (Heinen Surrebuttal).

226. The Company also proposed to review its current tariff in the next general rate case or in a separate docket to ensure that all customers are paying the appropriate cost of service and, if needed, will propose to modify the tariffs to consider situations where significant excess capacity exists. DOC Ex. 407 at 15 (Heinen Surrebuttal) (*citing* MERC Ex. 6 at 39-44 (Lee Rebuttal)).

D. OAG's Response to the Department's Analysis of Cost Mitigation

1. Potential sales to interruptible and transportation customers addresses the reserve margin issue

227. The OAG characterized the Department's position as one in which the provision of service to interruptible and transportation customers is used to establish need for the project. OAG Initial Brief at 68-72. It suggested that the Heinen Surrebuttal discussion of reserve margins pertained to planning for peak demand. *Id.* at 70. OAG took issue

with this position as so framed, arguing it would be "unreasonable to justify" the Rochester Project based on "expected increase in consumption by interruptible or transportation customers." *Id*. at 71.

228. The Department observed that this is a position that is not the Department's.

229. The Department's Direct Testimony concluded that the Project is reasonable, and the excess capacity costs were not significant. Based on its reserve margin analysis and its analysis of incremental capacity alternatives, the Department specifically concluded in its Direct Testimony that the size of MERC's proposed Project was reasonable. DOC Ex. 405 at 36 (Heinen Direct); DOC Ex. 406 at 1-3 (Heinen Rebuttal).

230. The Department's position in Direct was that excess capacity 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, and further, that there were methods by which MERC could mitigate those costs of excess capacity. DOC Ex. 405 at 36-37 (Heinen Direct).

231. The Department's Surrebuttal discussion of interruptible and transportation customers addressed the reserve margin issue; it was not directly related to establishing need. The Department's Surrebuttal Testimony did not modify its position that the proposed project was reasonable, but merely updated its excess capacity analysis (DOC Ex. 407 at 16 (Heinen Surrebuttal)) and concluded that expected usage by RPU, coupled with the fact that MERC had acquired 100 percent of incremental capacity in the Rochester Area, would likely result in a diminution of excess capacity related to the proposed Project. DOC Ex. 407 at 16 (Heinen Surrebuttal). That is, because MERC has obtained 100 percent of the incremental capacity in the Rochester Area, no other supply of natural gas capacity exists, and all customers, including new transportation customers in the area, should pay their fair share for the capacity costs of the Project. DOC Ex. 410 at 5 (Heinen Summary); Department Initial Brief at 60-65.

232. In Surrebuttal, the Department explained that MERC should be able to obtain near full or full rate recovery in the capacity release market because the third-party marketers with which transportation customers contract can buy only from MERC capacity deliverable in the Rochester Area. As a result, if MERC correctly negotiates capacity releases, these transportation customers will pay for capacity costs. DOC Ex. 407 at 13 (Heinen Surrebuttal); DOC Ex. 410 at 5-6 (Heinen Summary).

2. Size Is the Only Relevant Similarity between the Rochester Project and the MERC 2008 Bison Contract.

233. Mr. Heinen explained at trial that the relevance of the Bison contract to the present docket was that a comparison of the relative level of costs of the two situations helped put

the Rochester Project capacity costs in perspective, by comparing those costs to another project that MERC ratepayers are already being assessed.[38]

234. In 2008, MERC sought to diversify its supply of natural gas on its system and increase reliability, and entered into a contract that allowed MERC to procure gas priced off of the Colorado Interstate Gas (CIG) index price; at the time MERC decided to enter into the contract, the delivered cost of gas under the contract, including the commodity cost, was the least-cost option available to MERC.[39] Events occurring to gas markets beginning on July 1, 2008, however, caused the contract not to be as advantageous for MERC's customers as MERC had initially contemplated. Because the prudency or imprudency of actions of a regulated utility are assessed based on the situation that exists at the time costs are incurred, and are not based on hindsight, the Department recommended that the Bison contract was not unreasonable when entered into by MERC in 2008.[40] The Department further observed that "when total price is considered, the Bison Contract did not harm ratepayers and was prudently incurred at the time."[41]

235. The Commission agreed, adopted the Department's recommendations, and approved MERC's recovery of costs of the Bison contract as recommended by the Department.[42]

236. The two costs are similar in amount, ($38 per year for Bison and $32 per year for the Rochester Project), as Mr. Heinen explained in his Direct Testimony:

> 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. 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. 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

[38] 2 Tr. at 55.
[39] MPUC Dockets M-10-1166 and M-10-1168, Comments of the Department dated Nov. 15, 2011 at 2, 3 (Nov. 15 Comments); 2 Tr. 54-55.
[40] Nov. 15 Comments at 3, 4; 2 Tr. 55. The Department further recommended that, to ensure that all customers, including transportation and interruptible customers, paid a fair share of costs, the cost recovery by MERC should be through the commodity portion of the PGA, not the demand portion. Nov. 15 Comments at 9.
[41] Nov. 15 Comments at 4.
[42] MPUC Dockets M-10-1166 and M-10-1168, Order, January 21, 2015 at 2, and at Ordering Paras. 6 and 7.

> greater than the potential excess capacity costs associated with the Rochester project.

DOC Ex. 405 at 36 and AJH-20 and AJH-21 (Heinen Direct).

237. The OAG stated that the Bison contract involved "unreasonable costs," and implied that a thorough investigation could have been conducted (but was not). OAG Initial Brief at 75. In making this argument, the OAG did not acknowledge that the Commission investigated those costs in the 10-1166 and 10-1168 Demand Entitlement dockets, determined that the Bison contract was not unreasonable, and approved recovery from ratepayers of costs associated with it.[43]

238. While a comparison of the similar sizes of the cost recoveries relating to the Bison contract and the Rochester Project is informative of how the Commission may evaluate such costs, the similarity of the two situations need not be overstated. The Department recommended that the ALJ disregard inaccurate characterizations of the Bison contract. The ALJ adopts this recommendation.

239. MERC agreed that the Commission should require MERC to provide data for each capacity release associated with the Rochester Area over the most recent gas year in its future AAA filings and in the annual rider recovery filing in this 15-895 docket. DOC Ex. 407 at 14 (Heinen Surrebuttal); 1 Tr. at 20. The ALJ agrees.

240. The Department anticipates reviewing the releases to determine if the terms of the capacity release were reasonable based on market conditions. DOC Ex. 407 at 14 (Heinen Surrebuttal); 1 Tr. at 20.[44]

E. Summary

241. The Department recommended and the ALJ concurs that the Commission should find that the Project would likely result in temporary excess capacity costs that should be mitigated (DOC Ex. 410 at 6 (Heinen Summary)) and that the Company should be directed to explore the capacity release market and to determine whether changes can be made to facilitate the movement of customers from interruptible to firm service. DOC Ex. 410 at 6 (Heinen Summary).

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[43] Dockets M-10-1166 and M-10-1168, Order, January 21, 2015.

[44] Further, all MERC customers, including interruptible customers, need to pay their fair share, as suggested by the NGEP statute. Expanding the capacity of NNG's system makes it less likely, all else equal, that interruptible customers will be interrupted. The Department's recommendation that MERC appropriately assess the cost of capacity to interruptible customers and take steps to move interruptible customers to firm service, will prevent these customers from avoiding paying their share of costs to expand the capacity to the Rochester Area to the harm of other ratepayers. DOC Ex. 405 at 50 (Heinen Direct).

242. The Department recommended and the ALJ concurs that the Commission should direct MERC to reasonably pursue mitigation of costs for sales customers, including the use of long-term capacity release contracts, assessment of the cost of capacity to interruptible customers, movement of customers to firm service, sales of supplies to electric generation customers to mitigate excess capacity costs (DOC Ex. 410 at 6 (Heinen Summary)) and use of excess capacity to avoid purchasing other, more expensive, capacity to serve other parts of the MERC-NNG PGA system. DOC Ex. 405 at 60 (Heinen Direct).

6. COSTS OF THE PROJECT SHOULD BE RECOVERED FROM ALL CLASSES OF RATEPAYERS

A. Overview

243. Whether the Commission should require cost recovery from all classes of ratepayers, including transportation and interruptible customers[45] is disputed between MERC and the Department.

244. The Department concluded that gas commodity and demand costs should be recovered from all ratepayers, including transportation and interruptible customers.

245. MERC agreed that assessment of capacity costs to interruptible customers is appropriate, but did not agree that transportation customers should pay for natural gas capacity costs. At the evidentiary hearing, however, MERC stated that it agreed with the Department that "transport customers should be charged at a level that appropriately reflects the benefits they will receive as a result of the overall project." 1 Tr. at 20.

246. If the Project is approved, all parties in the Rochester Area would benefit from the increased natural gas capacity through either increased capacity in general, for transportation customers, or a decrease in the risk of curtailment, for interruptible customers. Thus, the Department concluded that it is appropriate for both sales and transportation, and firm and interruptible ratepayers to pay for a portion of the costs of the Project. DOC Ex. 410 at 4 (Heinen Summary). Failing to charge all ratepayers appropriately would require captive firm sales customers to bear the entire cost of the natural gas capacity of the proposed Project, despite the increase in natural gas capacity for transportation customers in the Rochester Area. DOC Ex. 410 at 4 (Heinen Summary).

B. Department's Analysis

247. 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; or, if recovery from all ratepayers is unreasonable, then what other allocation method would be more reasonable.

[45] This section concerns cost recovery of natural gas capacity and commodity costs that NNG charges to MERC, which MERC in turn charges to its ratepayers through the PGA. DOC Ex. 410 at 4 (Heinen Summary). Below is the discussion of the apportionment of revenue responsibility of non-gas, non-PGA related costs that are recovered through base rates.

248. Minn. Stat. § 216B.1638, subd. 2, states that a public utility "may petition the commission … 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." The NGEP Statute thus specifically requires all of MERC's customers, including transportation customers, to pay their share of the costs of the Project in a NGEP rider. DOC Ex. 410 at 5 (Heinen Summary).

249. MERC has an obligation to its sales customers to receive maximum benefit through the capacity release market, and certain customers, such as transportation customers, would receive unfair subsidies from sales ratepayers if they did not pay for natural gas capacity costs. DOC Ex. 410 at 5 (Heinen Summary).

250. The Department explained that it is unlikely that a firm transportation customer could bypass MERC's system, but if a customer threatened to do so, MERC has a tool under the flexible rate statute[46] to respond, if MERC showed that any the customer could actually bypass MERC's system. DOC Ex. 410 at 5 (Heinen Summary).

251. MERC agreed at the evidentiary hearing that the availability of the flex rate tariff would likely mitigate the rider increase for any potential bypass threat. 1 Tr. at 20.

252. The Department explained that MERC has obtained 100 percent of the incremental capacity in the Rochester Area; therefore, all customers, including new transportation customers in the area, should pay their fair share for the capacity costs of the Project because no other supply of natural gas capacity exists. DOC Ex. 410 at 5 (Heinen Summary).

253. The Department stated that it anticipates that it will review MERC's capacity release revenues each year to determine whether they were reasonable based on these market conditions, and MERC has agreed to provide this information. The Department's expectation is that prevailing market conditions should result in MERC being able to obtain nearly full rate recovery for use of this natural gas capacity. DOC Ex. 410 at 5-6 (Heinen Summary).

254. The Department stated that the Rochester Project involves the incremental costs of expanding the capacity of NNG's system. These costs are unusual and significant; it is important to ensure that rates appropriately reflect cost-causation, not just for fairness purposes, but also to avoid creating an inappropriate incentive for some of MERC's large customers to act in ways that would unduly and inappropriately harm other MERC customers. The cost of expanding NNG's capacity will be charged to MERC, and because that capacity will be used to serve all customers in the area regardless of whether the supplier is MERC or a third party, all customers, firm and interruptible, and both sales and transportation customers, need to pay their fair share of the cost of expanding NNG's capacity, consistent with the requirements of the NGEP Statute. That is, both sales and

[46] Minn. Stat. § 216B.163.

transportation customers need to pay their fair share, as suggested by the NGEP Statute. DOC Ex. 405 at 49-50 (Heinen Direct).

255. The Department further testified that expanding the capacity of NNG's system makes it less likely, all else equal, that interruptible customers will be interrupted. A decision to the contrary, that charged only sales customers for the costs of the Project would create an inappropriate incentive for 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. Similarly, a decision that charged only firm customers would create an inappropriate incentive for firm customers to switch to interruptible service and unduly benefit by avoiding paying for the cost of a system that is being built to serve them, to the harm of other ratepayers. DOC Ex. 405 at 50 (Heinen Direct).

C. MERC's Rebuttal and the Department's Response

256. In its Rebuttal Testimony, MERC agreed that assessment of capacity costs to interruptible customers is appropriate, but did not agree that transportation customers should pay for natural gas capacity costs. DOC Ex. 410 at 5 (Heinen Summary). MERC raised concerns about the Department's recommendations that transportation customers be assessed capacity costs associated with the proposed Project. DOC Ex. 407 at 9-10 (Heinen Surrebuttal). MERC concluded that the Department envisioned natural gas capacity costs being assessed to all customers through the monthly NNG PGA. MERC Ex. 6 19 (Lee Rebuttal).

257. The Department responded by noting that the Company's conclusion is correct regarding firm and interruptible customers, but incorrect as to transportation customers. The Department did not envision that transportation customers would be charged specific costs through the monthly PGA because MERC does not purchase gas for these customers as they arrange for delivery of their natural gas. DOC Ex. 407 at 10 (Heinen Surrebuttal). 1 Tr. at 110. Instead, the Department's recommendation pertained only to the capacity costs of the pipeline itself, not to natural gas supplies, which would be recovered through the rider for this Project costs. DOC Ex. 407 at 10 (Heinen Surrebuttal).

258. The Department saitd that transportation customers in the Rochester Area would benefit from the Project through increased pipeline capacity in the area through which natural gas supplied for these customers may be moved. *Id.* Transportation customers will pay for the Rochester Project to the extent that they purchase capacity on the NNG system when MERC sells capacity on the capacity release market. 1 Tr. at 20. Unless transportation customers pay for the pipeline capacity costs associated with the Project, the Company's sales customers would unfairly subsidize transportation customers. DOC Ex. 407 at 10-11 (Heinen Surrebuttal).

259. MERC raised two additional concerns associated with assessing these capacity costs: 1) transportation customers may be concerned that they will be assessed the same costs twice if capacity costs are charged by MERC and 2) there would be the risk of bypass

from certain transportation customers, which would result in higher costs for other customers if they leave the system. DOC Ex. 407 at 11 (Heinen Surrebuttal).

260. With respect to MERC's concern about charging transportation customers for the capacity costs of the Project, the Department's recommendation is consistent with the NGEP Statute and the Commission cannot vary the statute. DOC Ex. 407 at 12 (Heinen Surrebuttal).

261. As to the Company's bypass concerns in the Rochester Area, the concern is exaggerated. First, MERC has an important tool to address any bypass concerns. Minn. Stat. § 216B.163, the Flexible Rate Tariff, provides an opportunity to charge lower rates to customers (sales or transportation) based on a demonstration that the customer can bypass MERC's system. DOC Ex. 407 at 12 (Heinen Surrebuttal). MERC conceded at the evidentiary hearing that a flex rate would likely mitigate the rider increase attributable for the project.as to customers in Rochester that are bypass threats. 1 Tr. At 20.

262. The Department observed that MERC stated that existing capacity is completely sold out (1 Tr. at 137) and that the Company will acquire 100 percent of the incremental capacity added through the Rochester Project. DOC Ex. 407 at 2 (Heinen Surrebuttal) (*citing* MERC Ex. 6 at 18 and 24 (Lee Rebuttal)).

263. This point is important because potential transportation customers in the Rochester Area would be required to pay, if not directly, then indirectly, for the costs of the Project. DOC Ex. 407 at 11 (Heinen Surrebuttal). That is, these customers would pay for the costs of the Project because the Rochester Area is currently constrained and MERC will acquire 100 percent of the incremental capacity (DOC Ex. 407 at 13 (Heinen Surrebuttal)) and third party marketers will have no access to sources of capacity except via MERC. DOC Ex. 407 at 11 (Heinen Surrebuttal).

264. The Department noted that, if a customer wished to bypass the system (*e.g.,* Rochester Public Utilities) then not only would that customer need to construct a Town Border Station (TBS) and any associated facilities, it would also have to pay for its own capacity expansion, in much the same way that MERC proposes in this proceeding, on the NNG system. As evidenced by the cost data in the record, these bypass costs are substantial. The Company provided no specific information on the potential costs associated with RPU bypassing the MERC system for the Westside Energy Station. Without such information to demonstrate the existence of a bypass threat, the Department said, it is difficult to conclude that RPU represents a realistic threat to bypass MERC's system. DOC Ex. 407 at 12 (Heinen Surrebuttal).

265. Because of this circumstance, MERC should be able to obtain near full, or maximum, rate recovery in the capacity release market because the third-party marketers, with which transportation customers contract, can only buy capacity deliverable in the Rochester Area from MERC. These transportation customers will indirectly pay for capacity costs if the Company correctly negotiates these capacity releases. DOC Ex. 407 at 13 (Heinen Surrebuttal).

266. MERC currently provides information on capacity release in the Annual Automatic Adjustment (AAA) filing; however, these data are reported on a system wide basis. DOC Ex. 407 at 13-14 (Heinen Surrebuttal).

267. To ensure that the Company's firm, interruptible sales customers receive appropriate benefit from capacity release to third party marketers for delivery to customers in the Rochester Area, the Department recommended, and MERC agreed, that in future AAA filings, and in the annual rider recovery filing in this docket, the Company should be required to provide specific data for each capacity release associated with the Rochester Area over the most recent gas year (*i.e.*, July through June). DOC Ex. 407 at 14 (Heinen Surrebuttal); 1 Tr. at 20.

268. The Department explained that it anticipates reviewing these releases to determine whether the terms of the capacity release were reasonable based on market conditions. DOC Ex. 407 at 14 (Heinen Surrebuttal); 1 Tr. at 20.

D. Summary

269. The Department recommended, and the ALJ concurs, that both sales and transportation customers pay for the Project. Further, since expanding the capacity of NNG's system makes it less likely, all else equal, that interruptible customers will be interrupted, the Department recommended, and the ALJ agrees, that the costs of the Project be recovered from both firm and interruptible customers. DOC Ex. 405 at 60 (Heinen Direct).

270. The Department recommended, and the ALJ concurs, that because MERC has an obligation to its ratepayers, in particular its firm sales customers, to receive the highest revenues possible through the capacity release market and to prevent the Company's customers from unfairly subsidizing other parties wishing to use MERC's excess capacity, the Commission should require MERC to provide in future AAA filings and in the annual rider recovery filing in this docket, specific data for each capacity release associated with the Rochester Area over the most recent gas year (i.e., July through June). DOC Ex. 405 at 58-61 (Heinen Direct); DOC Ex. 407 at 15 (Heinen Surrebuttal).

271. MERC agrees with the recommendation for AAA filings. 1 Tr. at 20.

7. MERC'S REQUEST FOR PROPOSAL (RFP) PROCESS WAS REASONABLE.

272. The Department reviewed MERC's RFP process, and concluded that it was a reasonable, comprehensive gauge of the market and potential alternatives for obtaining interstate pipeline services to the Rochester TBSs. The Department concluded that MERC made reasonable efforts to address this issue through the timing of the process and by allowing other bidders the opportunity to provide competitive bids on the Project. Overall, the Department concluded that MERC had demonstrated its RFP process to be fair and reasonable, and that MERC had negotiated reasonable provisions for ratepayers. DOC Ex. 402 at 14-15 (Ryan Direct); DOC Ex. 404 at 3 (Ryan Surrebuttal); DOC Ex. 409 at 1 (Ryan Summary).

A. Department Witness Michael Ryan

273. Mr. Michael Ryan addressed the RFP process conducted by MERC for its Rochester Project. Mr. Ryan investigated whether MERC's RFP process was administered in an equitable manner, in line with industry standards, whether it was inclusive of potential parties, and whether participating parties were held to a fair process. DOC Ex. 409 at 1 (Ryan Summary).

274. Mr. Ryan has significant experience regarding issuance and evaluation of RFPs for natural gas. Prior to joining the Department of Commerce as a Public Utilities Rates Analyst in February of 2016, he had seven and a half years' experience in the natural gas industry. He worked with U.S. Energy Services, Inc., a company that, among other things, manages and procures natural gas supply using RFPs. From 2009 to 2012, he was a Gas Operations Analyst. He coordinated natural gas transportation on the major interstate pipelines in Minnesota, including NNG, Northern Border Pipeline Co. (NBPL), Viking Gas Transmission Co. (Viking), Alliance Pipeline L.P. (Alliance), and Great Lakes Gas Transmission L.P. (GLGT).[47] From 2012 until 2016, he held the position of Retail Energy Originator, and issued in excess of 75 RFPs for natural gas per year across North America. He established the RFP timing and bidding factors specific to each retail facility, evaluated the responses to the RFPs he issued, and was responsible for delivered retail natural gas supply contracts resulting from the RFP processes. DOC Ex. 402 at 1 (Ryan Direct).

B. Options for Meeting MERC's Forecasted Need

275. On behalf of the Department, Mr. Ryan reviewed MERC's testimony on the various options it assessed for meeting MERC's forecasted need. DOC Ex. 402 at 4-6 (Ryan Direct). The Company had assessed six alternatives, and explained the benefits and deficiencies of each as follows as follows:

1. Take No Action

The Company stated that taking no action was not reasonable because there is shortfall of delivery entitlement to the Rochester city gates, that with demand expected to grow, MERC will need additional capacity, and there is no incremental capacity for sale from NNG or other shippers transporting natural gas to Rochester. DOC Ex. 402 at 4 (Ryan Direct) (*citing* MERC Ex. 12 at 8 (Mead Direct)).

2. Conservation

MERC stated that conservation of energy has been insufficient to eliminate the growth in demand. MERC Ex. 12 at 8 (Mead Direct). The Company further explained that demand side savings are insufficient to meet the anticipated

[47] Many of these pipelines were the same companies that participated in MERC's competitive bidding process in this docket.

customer growth and current shortfall. DOC Ex. 402 at 4 (Ryan Direct) (*citing* MERC Ex. 12 at 9 (Mead Direct)).

3. Upgrading Only the MERC Distribution System

MERC indicated that there are limits to the option of upgrading only the MERC distribution system, based on the amount of natural gas that can be delivered to the Rochester TBSs from the upstream interstate pipeline. Upgrades to MERC's distribution system address only issues downstream from the two Rochester TBSs, not the constrained interstate pipeline and flow into the TBSs. DOC Ex. 402 at 4-5 and MR-2 (Ryan Direct) (*citing* MERC Ex. 12 at 9 (Mead Direct).

4. Realignment of Other MERC-Owned Northern Natural Gas (NNG) Capacity

According to MERC, there are two TBSs where NNG delivers natural gas to the Rochester Area: Rochester 1B and 1D MERC Ex. 17 at 7 (Sexton Direct). While the Company has 193,423 Dekatherms (Dth)/day of firm delivery entitlement on NNG to stations other than Rochester 1B & 1D (MERC Ex. 17 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. DOC Ex. 402 at 5 (Ryan Direct) (*citing* MERC Ex. 17 at 9 and 10 (Sexton Direct)). In other words, the other capacity is already needed at other delivery points. DOC Ex. 402 at 5 (Ryan Direct). 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 because it too would require NNG to expand physical delivery capability elsewhere to ultimately serve Rochester. DOC Ex. 404 at 4 (Ryan Surrebuttal).

5. Purchase of Capacity from Other Interstate Pipelines

No other pipelines serve Rochester, so the purchase of capacity from other interstate pipelines was not an option. While service from other pipelines is not impossible, other pipelines would have to build infrastructure to reach Rochester. DOC Ex. 402 at 5 (Ryan Direct) (*citing* MERC Ex. 17 at 12 (Sexton Direct)).

6. Use Peaking Facilities to Address Need for Distribution Capacity

The 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 peaking facilities on its system and adding peaking facilities would not be a solution for serving Rochester, because the distribution system had reached capacity. Similar to the third option above, this alternative could address only MERC's distribution system and not the constraint on the interstate pipeline. DOC Ex. 402 at 6 and MR-3 (Ryan Direct).

C. The Department's Evaluation of MERC's RFP Process

276. The Department evaluated MERC's RFP process to assess whether the RFP was inclusive of all potential responding parties, and whether the participating parties were held to a fair process; the Department also reviewed the results of the RFP to determine whether MERC had selected the lowest cost option, and ensured there were reasonable provisions in the resulting contract to protect ratepayers. DOC Ex. 402 at 6 (Ryan Direct).

1. The Request Was Inclusive of All Potential Parties.

277. On January 5, 2015 MERC issued an RFP to several companies, including NNG, NBPL, Viking, GLGT, and Encore. DOC Ex. 402 at 6 (Ryan Direct) (*citing* MERC Ex. 17 at 38 (Sexton Direct)). MERC included multiple parties to determine whether the best and most cost effective option was to remain with NNG, the incumbent provider of service to Rochester. *Id.* at 3. The RFP was also posted to the MERC publicly-accessible website to allow for additional solicitation. *Id.* at 6.

278. The Department concluded that MERC's RFP solicitation was reasonably inclusive of potential parties. DOC Ex. 402 at 7-8 (Ryan Direct).

279. Only one potential bidder, Alliance, was not directly solicited; the record shows that Alliance nevertheless was aware of the RFP and did not submit a formal response.[48] The Alliance pipeline travels through southern Minnesota near the Rochester Area. In response to Department discovery, MERC stated that it did not specifically solicit Alliance because Alliance is a "wet" pipeline,[49] which would have necessitated building an additional processing plant, making use of the Alliance pipeline cost prohibitive and impractical. DOC Ex. 402 at 7 and MR-4 (Ryan Direct) (MERC Response to DOC IR No. 44). Mr. Ryan explained that, for MERC to obtain supply from a wet pipeline, a processing plant would have been needed at the interconnection between Alliance and MERC's distribution system, to extract hydrocarbon liquids and allow the "dry" natural gas to flow into Rochester.

280. Mr. Ryan concluded, based on these facts that MERC should have specifically 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, because Alliance was aware of the RFP but did not

[48] A consultant for Alliance made an inquiry to MERC based on the RFP, which indicated that Alliance was aware of the RFP; no bid was received from Alliance. DOC Ex. 405 at 7 and MR-4 (Ryan Direct) (MERC Response to DOC IR No. 44).

[49] Mr. Ryan explained that when natural gas is extracted or gathered from the natural gas field, additional hydrocarbon liquids and impurities are mixed with the natural gas. A pipeline is a "wet" pipeline when it is able to transport a denser hydrocarbon mix and extract the additional hydrocarbons at the point of delivery instead of at the extraction point. DOC Ex. 405 at 7 (Ryan Direct).

submit a bid, he concluded that MERC had reasonably addressed the issue of whether its RFP had been appropriately inclusive of possible bidders. DOC Ex. 402 at 7-8 (Ryan Direct).

2. The Participating Parties Were Held to a Fair Process in the RFP.

281. The Department reviewed the RFP[50] and concluded that the RFP documents were sufficiently detailed and, because they included two Project sizes to allow for full Project comparison between the incumbent pipeline company, NNG, and the other bidders, concluded that the RFP included sufficient guidance and data for companies to adequately respond to MERC's needs. DOC Ex. 402 at 8 (Ryan Direct).

282. The Department concluded that the RFP documents allowed respondents adequate time to respond, where the RFP requested responses two weeks after the date of issuance. Mr. Ryan explained that industry practice varies considerably, depending on the level of complexity and other factors, but in his opinion, the two week timeframe did allow for responses or, at a minimum, indications of intent from potential parties. DOC Ex. 402 at 8 (Ryan Direct). During that time, MERC received multiple responses to the RFP, including from NNG, NBPL, and a bidder not specifically solicited, Twin Eagle.[51] DOC Ex. 402 at 8 (Ryan Direct). The responses were received within the requested timeframe. A MERC Witness, Mr. Sexton, said 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. DOC Ex. 402 at 9 (Ryan Direct) (*citing* MERC Ex. 17 at 41 (Sexton Direct)).

283. There were multiple bid options provided as part of the RFP. The RFP included two scenarios. The use of two scenarios was intended to address the fact that NNG is the incumbent pipeline serving MERC in the Rochester Area. The first option was 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. DOC Ex. 402 at 6 (Ryan Direct).

D. MERC Selected the Lowest Cost Option.

284. The Department reviewed the RFP responses and MERC's internal review of the competitive bid process. DOC Ex. 402 at 9-10 (Ryan Direct) (*citing* DOC Ex. 403 at MR-6 and MR-1 (Ryan Highly Sensitive Trade Secret Direct) (MERC's Highly Sensitive Trade Secret Responses to OAG IR No. 132 and DOC IR No. 38)). MERC's internal review was a high level summary of the pricing provided by suppliers along with other

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[50] MERC provided the RFP in response to discovery. DOC Ex. 402 at 8 and MR-5 (Ryan Direct) (Response to OAG IR No. 132).

[51] Twin Eagle is a midstream operator and wholesale marketer of natural gas. *http://www.twineagle.com/*

non-quantitative aspects that were factored into the Company's decision.[52] All categories were weighted with Project cost holding the majority of the weight. DOC Ex. 402 at 10 (Ryan Direct).

285. The Department concluded that the weights MERC assigned in MERC's baseline summary document of the RFP results were reasonable, and that 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. DOC Ex. 402 at 10 (Ryan Direct).

286. MERC enlisted the services of Mr. Sexton to review MERC's RFP process independently. DOC Ex. 402 at 10 (Ryan Direct). MERC provided Mr. Sexton's independent evaluation in MERC Ex. 18 at HSTS TCS-3 (Sexton Direct HSTS Exhibit 3).

287. Mr. Sexton's comparison focused solely on pricing and reached the same conclusion as MERC did, that the results of the RFP indicate that NNG was the most competitive option for moving forward with the Rochester Expansion. DOC Ex. 402 at 10-11 (Ryan Direct).

288. In reviewing Mr. Sexton's analysis, the Department concluded that Mr. Sexton's assumptions and additional cost component calculations were accurate; further, the Department was able to tie Mr. Sexton's statements to the responses provided by the bidding parties and confirmed the calculations. DOC Ex. 402 at 11 (Ryan Direct).

289. The Department determined that MERC's position, that NNG's Proposal 3.0 was the most competitive bid, was reasonable. DOC Ex. 402 at 11 (Ryan Direct).

290. NNG Proposal 3.0 was received on February 18, 2015 with the competitive bids of the other pipeline companies and became the basis for additional negotiations and later amendments.

291. Observing that, after the formal RFP process was closed, additional components were negotiated with NNG, Mr. Ryan further testified that because these 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. DOC Ex. 402 at 11 (Ryan Direct) (*citing* MERC Ex. 17 at 51 (Sexton Direct)).

292. The amended option 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. DOC Ex. 402 at 11 (Ryan Direct) (*citing* MERC Ex. 17 at 45 and 46 (Sexton Direct)).

[52] Although not included in its Petition, MERC provided the summary results of the RFP process in response to Department discovery. DOC Ex. 403 at 3 and MR-1 (Ryan Direct-HSTS)(Response to DOC IR No. 38 (HSTS)).

293. While the final amended negotiated transaction with NNG (which included the phased approach) increased the total cost of the Project in nominal dollars as a result of delaying Phase 1 of the Project to November 1, 2018 (instead of November 1, 2017), the delay resulted in an increased capital cost of approximately $2.5 million or less than 5 percent. DOC Ex. 402 at 12 (Ryan Direct) (*citing* MERC Ex. 12 at 15 (Mead Direct)).

294. Mr. Ryan stated that these capital cost increases did not have a material impact on the results of the RFP process and NNG would still have prevailed relative to the other bids even with these increased cost. DOC Ex. 402 at 12 (Ryan Direct).

E. MERC Negotiated Reasonable Provisions in the Resulting Contract to Protect Ratepayers.

295. The Department concluded that additional components that made NNG the best option.

296. 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, such that the reservation price would not increase if NNG files with the Federal Energy Regulatory Commission for increased tariff rates. DOC Ex. 403 at 12 and MR-1 (Ryan Highly Sensitive Trade Secret Direct) (MERC Highly Sensitive Trade Secret Response to DOC IR No. 38).

297. Additional negotiated enhancements in the Amended Negotiated Transaction added flexibility and certainty to extension rights as follows:

a. <u>Fixed delivery rates for the existing Rochester entitlement:</u> The rates are not subject to change when NNG's maximum tariff rates change; instead, the existing Rochester entitlement would be fixed at the current maximum rate during the 25-year term of the agreement. DOC Ex. 402 at 13 (Ryan Direct) (*citing* MERC Ex. 17 at 47 and 48 (Sexton Direct)).

b. <u>Firm growth capacity rights to other MERC markets:</u> 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. DOC Ex. 402 at 13 (Ryan Direct) (*citing* MERC Ex. 17 at 48 (Sexton Direct)). The firm capacity would be at NNG's maximum tariff rate.

c. <u>Flexibility to use Rochester TF entitlement to serve markets other than Rochester:</u> 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. DOC Ex. 402 at 13 (Ryan Direct) (*citing* MERC Ex. 17 at 49 (Sexton Direct)). The NNG market zone EF covers all of Minnesota. MERC is able to use up to 20 percent of the total Rochester capacity throughout the state. DOC Ex. 402 at 13 (Ryan Direct) (*citing* MERC Ex. 12 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. DOC Ex. 402 at 13 (Ryan Direct) (*citing* MERC Ex. 12 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. 402 at 13-14 MR-7 (Ryan Direct) (MERC Response to OAG IR No. 185- Attachment OAG 185.xlsx).

d. 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. DOC Ex. 402 at 14 (Ryan Direct) (*citing* MERC Ex. 17 at 50 (Sexton Direct)).

e. 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. DOC Ex. 402 at 14 (Ryan Direct) (*citing* MERC Ex. 17 at 50 (Sexton Direct).

F. MERC's RFP Process Was Not Compromised by MERC's Request in the RFP for Only One Size of Project.

298. In response to the OAG's concern that MERC's RFP process may not have been reasonable because the RFP requested only one size of project, Mr. Ryan explained that it is beneficial for entities issuing RFPs to provide specific parameters in the RFP to allow the bids to be compared on an apples-to-apples basis. The method that MERC used allowed it to compare the three bids equally. If the MERC RFP had requested multiple sizes of proposals, as was suggested by the OAG, the Company would have received varying responses that would have been difficult to compare in a meaningful manner. Also, under the process used by MERC, if the RFP had needed to be adjusted or refreshed with a different size, MERC could have issued an amended RFP with the new size preference. DOC Ex. 404 at 1- 2 (Ryan Surrebuttal).

G. Summary

299. Based on its investigation, the Department generally concurred with Mr. Sexton's Direct Testimony regarding the RFP conducted by MERC. The Department concluded that the RFP process was a comprehensive gauge of the market and the potential alternatives for interstate pipeline services to the Rochester TBSs. The Department concluded that, while other pipelines may have difficulty serving Rochester, MERC made reasonable efforts to address this issue through the timing of the process and by allowing other bidders the opportunity to provide competitive bids on the Project. DOC Ex. 402 at 14-15 (Ryan Direct). The ALJ concurs with these conclusions

300. The Department recommended and the ALJ agrees, that the Commission should find that MERC's RFP process was fair and reasonable, and that MERC negotiated reasonable provisions for ratepayers in Rochester and elsewhere in MERC's system. DOC Ex. 402

at 14 (Ryan Direct); DOC Ex. 404 at 3 (Ryan Surrebuttal); DOC Ex. 409 at 1 (Ryan Summary).

8. RATE DESIGN AND APPORTIONMENT OF REVENUE RESPONSIBILITY

A. Overview

301. Rate design and the apportionment of revenue responsibility are disputed between MERC and the Department.

302. The Department recommended that, because rates should reasonably reflect the costs of serving customers (DOC Ex. 401 at 4 (Peirce Surrebuttal)) the Commission should require MERC to apportion at least 50 percent of the revenue deficiency to MERC's Rochester customers and the remaining amount to MERC's non-Rochester customers. DOC Ex. 401 at 8-9 (Peirce Surrebuttal).

303. Minn. Stat. § 216B.1638 subd. 2 (a) permits gas utilities to petition the Commission outside of a general rate case for a rider to recover the costs of a NGEP from all of the utility's customers, including transport customers. Recovery under the rider can be no more than one-third (33 percent) of the costs of the NGEP. Minn. Stat. § 216B.1638, subd. 3 (c).

B. Description of the MERC proposal

304. MERC proposed to recover through an NGEP rider one-third of the revenue deficiency associated with the upgrade of its distribution system in the Rochester Area. MERC proposed to file its annual NGEP rider by October 1 each year, and for the rates under the rider to be effective January 1st of the subsequent year. MERC proposed that, in the annual filing, it will identify the projected rider-eligible revenue deficiency and the proposed per-therm rider rate. MERC further proposed that the NGEP rider rate be calculated annually, and include a true-up to reflect actual revenues and expenses. DOC Ex. 400 at 2-3 (Peirce Direct) (*citing* MERC Ex.5 at 17 (Lee Direct).

305. MERC proposed to apportion responsibility for its Rochester Project revenue requirement among its customer classes by recovering the rider revenue deficiency on a flat per-therm basis from all customers. Under this proposal, the rider rate would be calculated by dividing the annual revenue deficiency by the number of total therm sales to all customers, including transport customers. DOC Ex. 400 at 3 (Peirce Direct).

C. Department's Analysis

306. The Department concluded that the Company's proposed rate design recommendation, to recover its costs on a per-therm basis was reasonable, and observed that this design would simplify the rider. DOC Ex.400 at 3 (Peirce Direct); DOC Ex. 401at 1 (Peirce Surrebuttal); DOC Ex. 408 at 1 (Peirce Summary).

307. With respect to apportionment of the revenue deficiency, the Department Witness, Ms. Peirce, concluded that the issue was somewhat more complex than was reflected in

MERC's proposal. MERC proposed a flat per-therm rate applied to *all* customers, while Ms. Peirce recommended that the revenue deficiency, which is to be recovered under MERC's NGEP rider, should recover at least fifty percent of the costs from ratepayers in Rochester, and the remainder charged to ratepayers outside of Rochester, before calculating the flat per-therm charge for each group of customers.[53] DOC Ex. 400 at 3 (Peirce Direct); DOC Ex. 401 at 1-2 (Peirce Surrebuttal); DOC Ex. 408 at 1 (Peirce Summary).

308. The Department recommended a fifty/fifty (or other) apportionment of the revenue requirement between Rochester and non-Rochester customers because, while MERC customers outside the Rochester Area would benefit from improved reliability (DOC Ex. 402 at 14 (Ryan Direct) (*citing* MERC Ex. 17 at 50 (Sexton Direct)) the Project would most directly benefit Rochester Area customers, by improving reliability in the Rochester Area and by allowing for additional growth with the addition of the proposed DMC. DOC Ex. 400 at 3-4 (Peirce Direct); DOC Ex. 408 at 1 (Peirce Summary).

309. The Department said that apportioning half the NGEP rider costs to Rochester is reasonable because Rochester customers represent approximately 20 percent of MERC's total customer base, and 13.5 percent of MERC's total sales, and such an apportionment would more accurately reflect cost-causation of the Project. DOC Ex. 400 at 4 (Peirce Direct) (*citing* MERC Ex. 9 at 10 (Clabots Direct) *and* MERC Ex. 5 at ASL-1 (Lee Direct)).

310. In addition, the Deparment explained, because the Project would accommodate growth in sales in the Rochester Area, the burden of the higher apportionment per Mcf would be reduced over time. DOC Ex. 400 at 4 (Peirce Direct).

311. MERC's proposal to spread the costs of the Rochester Project equally across all customers was based on an over-simplification of the NGEP rider statute, which authorized rider recovery from "all of the utility's customers, including transport customers." DOC Ex. 401 at 2 (Peirce Surrebuttal) (*citing* MERC Ex. 6 at 10 (Lee Rebuttal)).

312. The Department determined that MERC's reading of the NGEP Statute is an oversimplification because, while the the NGEP Statute requires recovery from all customers, including transport customers, it does not mandate that the recovery be distributed *equally* among customers, in disregard of cost causation principles. DOC Ex. 401 at 2, 3 (Peirce Surrebuttal).

313. Minn. Stat. § 216B.1638, subd. 2(a) requires all customer classes to share in the revenue recovery, but it does not require the rates to be the same for all customers. DOC Ex. 401 at 2 (Peirce Surrebuttal).

[53] The 50/50 allocation of costs refers to the amount remaining after assignment of costs to Rochester Public Utilities. DOC Ex. 400 at 3-4 (Peirce Direct); DOC Ex. 401 at 4 (Peirce Surrebuttal).

314. Further, Minn. Stat. § 216B.1638, subd. 2b of the statute expressly allows a utility to file with its rider petition its proposals regarding:

- the amount of the revenue deficiency, and how recovery of the revenue deficiency will be allocated among industrial, commercial, residential, and transport customers; and
- 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.

Minn. Stat. § 216B.1638, subd. 2b (6) and (7).

315. These provisions contemplate that a utility may propose to apportion the revenue deficiency among its customer classes on a basis of its choosing, and to propose different methods of recovery for the revenue deficiency apportioned to each customer class. DOC Ex. 401 at 3 (Peirce Surrebuttal).

316. The Department said its proposed recovery method is consistent with the NGEP rider statute, and, unlike MERC's proposal, is reasonable because it reflects cost causation principals.

317. MERC also opposed creating separate rate zones in the MERC system because the Company prefers to consolidate its various operating companies and eliminate rate disparities among its customers. DOC Ex. 401 at 2 (Peirce Surrebuttal) (*citing* MERC Ex. 6 at 10 (Lee Rebuttal)) and because MERC believes uniformity is consistent with Commission precedent that spreads system upgrade costs across an entire rate base. DOC Ex. 401 at 2 (Peirce Surrebuttal) (*citing* MERC Ex. 6 at 10 (Lee Rebuttal)).

318. The Department disagreed with MERC's arguments, noting, first, MERC's interest in system-wide uniformity should not override the greater interest in establishing a reasonable allocation that reflects cost causation.

319. The Department said that, second, its proposed allocation is reasonable for the further reason that the amount of the differential between Rochester Area and non-Rochester Area customers is reasonable. The purpose of this proceeding is to develop the revenue deficiency and rate recovery for the NGEP rider. The rider reflects only one-third of the Project's costs, and will be a separate line item on customer bills. The 50/50 split of costs refers only to the amount remaining *after* assignment of capacity costs to customers such as Rochester Public Utilities. DOC Ex. 400 at 3-4 (Peirce Direct); DOC Ex. 401 at 4 (Peirce Surrebuttal).

320. At some point MERC will file to include the Rochester Project in base rates, and the Commission and parties will be free to revisit the appropriate apportionment of costs among MERC's customers at that time. Consequently, the Department did not expect that the rate differentials it proposes between Rochester and non-Rochester customers will be a long-term separate rate zone. DOC Ex. 401 at 3-4 (Peirce Surrebuttal).

321. Third, implicit in MERC's position is that customers in Northern Minnesota, for example, would benefit from this Project on the same per-kWh basis as customers in Rochester. However, the Rochester Project would most directly benefit Rochester Area customers, by improving reliability and allowing for additional growth with the addition of the proposed DMC, while customers outside the Rochester Area would benefit from improved reliability. DOC Ex. 400 at 3-4 (Peirce Direct); DOC Ex. 401 at 4 (Peirce Surrebuttal) (*citing* DOC Ex. 402 at 14 (Ryan Direct)).

322. Fourth, as noted above, the NGEP Statute contemplates that rates may be different for different classes of customers. Consequently, the Commission's options for setting rates in this proceeding are not limited by the utility's internal rate design goals. Instead, rates should reasonably reflect the costs of serving customers. DOC Ex. 401 at 4 (Peirce Surrebuttal). The Rochester Area receives the most immediate benefit, and should pay a bit more as a result. DOC Ex. 401 at 4 (Peirce Surrebuttal).

323. Fifth, contrary to MERC's assertion, that the Commission "typically" requires system upgrade costs to be recovered equally from all customers, such an outcome may occur when costs of projects are built into base rates in a rate case, but this is a rider petition, not a rate case. Rider petitions typically result in different allocations of costs of new projects to ratepayers. DOC Ex. 401 at 5 (Peirce Surrebuttal).

324. Finally, this is the first time the Commission is determining recovery under the NGEP Statute. The Commission is free to craft the recovery methodology that it feels best fits the Rochester Project. DOC Ex. 401 at 5 (Peirce Surrebuttal).

325. The Department requested that MERC calculate the rates based on a fifty/fifty allocation between Rochester and non-Rochester customers with separate per-therm rates for the two groups, and provide a bill impact analysis. DOC Ex. 400 at 5 (Peirce Direct). Tables 1 and 2 summarize average monthly bill impacts under the Department's and MERC's proposals.[54]

[54] The non-Rochester Large Volume and Super Large Volume customer classes include customers subject to Minn. Stat. § 216B.1696, the Energy-Intensive Trade-Exposed (EITE) statute. Minn. Stat. § 216B.1695, subd. 2 states that "It is the energy policy of the state of Minnesota to ensure competitive electric rates for energy-intensive trade-exposed customers." Thus the rate increases for such customers should be moderated. DOC Ex. 401 at 6 (Peirce Surrebuttal).

Peirce Surrebuttal Table 1: Summary of Average Monthly Bill Impact in 2017

Class	MERC Prop.	DOC-Rochester	DOC Non-Rochester	DOC-Rochester-less MERC	DOC Non-Rochester less MERC
Residential	$0.007	$0.023	$0.004	$0.016	($0.003)
Small C&I	$0.008	$0.027	$0.004	$0.019	($0.004)
Large C&I	$0.060	$0.230	$0.040	$0.170	($0.020)
Sm. Vol Interrupt-Sales	$0.400	$1.420	$0.230	$1.020	($0.170)
Sm. Vol. Joint Sales	$0.410	$1.440	$0.240	$1.030	($0.170)
Sm. Vol. Interrupt-Transp.	$0.980	$3.450	$0.570	$2.470	($0.410)
Sm. Vol. Joint Transp.	$0.710	$2.500	$0.410	$1.790	($0.300)
Transport for resale	$1.980	$7.020	$1.150	$5.040	($0.830)
Lg. Vol. Interrupt-Sales	$1.700	$6.020	$0.990	$4.320	($0.710)
Lg. Vol. Interrupt-Transp.	$12.350	$43.730	$7.190	$31.380	($5.160)
Lg. Vol. Joint Transp.	$9.990	$35.380	$5.810	$25.390	($4.180)
Super Lg Vol. Interrupt-Transp	$116.790	$413.740	$67.990	$296.950	($48.800)
Super Lg. Vol. Joint-transp	$43.400	$153.740	$25.260	$110.340	($18.140)

DOC Ex. 401 at 7 (Peirce Surrebuttal).

Peirce Surrebuttal Table 2: Summary of Average Monthly Bill Impact in 2020

Class	MERC Prop.	DOC-Rochester	DOC Non-Rochester	DOC-Rochester-less MERC	DOC Non-Rochester less MERC
Residential	$0.090	$0.310	$0.050	$0.22	($0.04)
Small C&I	$0.107	$0.360	$0.060	$0.25	($0.30)
Large C&I	$0.910	$3.100	$0.530	$2.19	($2.57)
Sm. Vol Interrupt-Sales	$5.630	$19.180	$3.300	$13.55	($15.88)
Sm. Vol. Joint Sales	$5.710	$19.440	$3.350	$13.73	($16.09)
Sm. Vol. Interrupt-Transp.	$13.740	$46.770	$8.050	$33.03	($38.72)
Sm. Vol. Joint Transp.	$9.950	$33.870	$5.830	$23.92	($28.04)
Transport for resale	$27.950	$95.140	$16.380	$67.19	($78.76)
Lg. Vol. Interrupt-Sales	$23.960	$81.560	$14.040	$57.60	($67.52)
Lg. Vol. Interrupt-Transp.	$173.980	$592.360	$101.970	$418.38	($490.39)
Lg. Vol. Joint Transp.	$140.740	$479.180	$82.480	$338.44	($396.70)
Super Lg Vol Interrupt-Transp	$1,645.960	$5,603.940	$964.650	$3,957.98	($4,639.29)
Super Lg Vol Joint-transp	$611.610	$2,082.330	$358.450	$1,470.72	($1,723.88)

DOC Ex. 401 at 8 (Peirce Surrebuttal).

D. The NNG Purchased Gas Adjustment (PGA)

326. MERC proposed 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. DOC Ex. 400 at 4 (Peirce Direct).

327. Based on the testimony of Department Witness Mr. Adam Heinen regarding MERC's proposal to charge to ratepayers the portion of the costs charged to MERC by NNG for the additional interstate pipeline capacity to the area through the NNG PGA, the Department recommended that the Commission approve recovery of NNG pipeline capacity costs through MERC's NNG PGA. DOC Ex. 400 at 5 (Peirce Direct); DOC Ex. 408 at 1 (Peirce Summary).

E. Summary

328. The Department recommended, and the ALJ concurs, 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 and calculated on a per-therm basis for each group; and

329. The Department recommended, and the ALJ concurs, that the Commission approve recovery of NNG pipeline capacity costs through MERC's NNG PGA. DOC Ex. 401 at 8-9 (Peirce Surrebuttal).

9. FUNDING AVAILABILITY FROM OTHER SOURCES

A. Overview

330. This issue is not in dispute. The Department concluded that the Project is not presently eligible for state infrastructure aid funding because it does not take place within the boundaries of the DMC District. DOC Ex. 410 at 3-4 (Heinen Summary). If future work occurs in the DMC development district, the Commission should require MERC to seek this funding and report on its efforts.

B. Department's Analysis

331. 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 pertains to the proposed DMC in Rochester and the associated State Infrastructure Aid (SIA) program authorized by Minn. Stat. § 469.47. State funds are available for approved public infrastructure once private investment in the DMC area reaches a certain threshold.[55] DOC Ex. 405 at 51 (Heinen Direct).

332. The 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 were enacted to aid in the implementation of the DMC and create various state and local funding streams to facilitate this implementation. DOC Ex. 405 at 51 (Heinen Direct). 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 charged with approval of projects before they are forwarded to the City of Rochester for final approval.

333. The DMC Statutes also authorized the creation of a development plan outlining the various goals and planned projects for the DMC and 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 reaches a defined threshold. DOC Ex. 405 at 51-52 (Heinen Direct).

334. A draft of the DMC development plan is available on the DMC website and the Department reviewed the entirety of the DMC development plan. DOC Ex. 405 at 52 (Heinen Direct).

335. The Rochester Project relates to the DMC because implementation of the DMC is extremely difficult, if not impossible, unless MERC makes the upgrades associated with the proposed Rochester Project because the Rochester Area is capacity constrained in terms of natural gas and the planned construction and expansions in the DMC development plan will not otherwise have access to sufficient natural gas supplies. It

[55] Minn. Stats. §§ 469.40 through 469.47 (the DMC Statutes) are attached to the Heinen Direct as DOC Ex. 405 at AJH-28 (Heinen Direct).

would complicate development and require incremental growth if the development were to rely entirely on the local electric utility to supply various needs such as space heating.

336. The Department said that the Rochester Project meets the definition of a public infrastructure project. Public infrastructure is defined as infrastructure owned by the public or for public use, which utility and energy infrastructure constitutes. DOC Ex. 405 at 53 (Heinen Direct). Minn. Stat. § 469.40 subd. 11 (a) defines "public infrastructure project":

> 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:
>
> **(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;

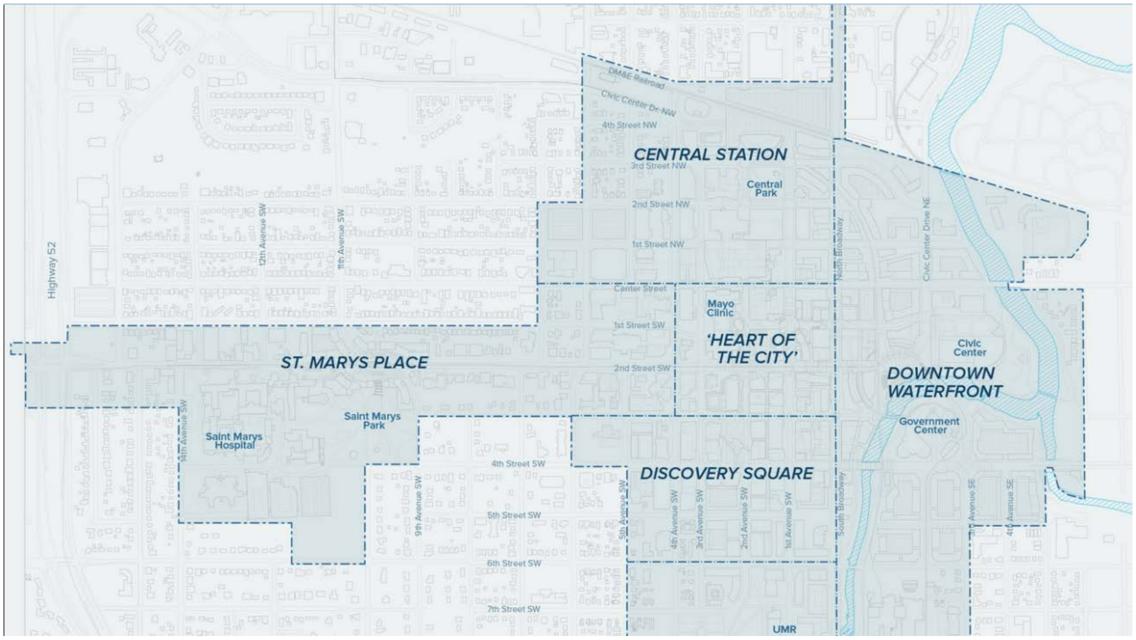
Minn. Stat. § 469.40 subd. 11(a) (emphasis added).

337. The bolded section above shows that the type of utility work MERC envisions is classified by DMC Statute as public infrastructure. DOC Ex. 405 at 54 (Heinen Direct). The current capacity constraint in the Rochester Area means that MERC's natural gas infrastructure is required to support the overall development of the destination medical center development district. DOC Ex. 405 at 54 (Heinen Direct).

338. An infrastructure project may be eligible for SIA funding in the "development district." Minn. Stat. § 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." DOC Ex. 405 at 54-55 (Heinen Direct).

339. The map below, taken from the development plan, outlines the development district.

Heinen Direct Map 1: Current DMC Boundaries and Sub-districts



DOC Ex. 405 at 55 (Heinen Direct).

340. The development district, as currently defined, is located in downtown Rochester in and around the Mayo Clinic Campus. DOC Ex. 405 at 55 (Heinen Direct).

341. Based on its review of the draft DMC development plan, the DMC Statutes, and the Company's Application, the Department concluded that the Company's Project cannot be considered a public infrastructure project that is eligible for SIA funding. The Project meets the definition of a public infrastructure project, and will help facilitate the implementation of the DMC by relieving natural gas constraints in the Rochester Area, but does not appear to meet the definition in the DMC Statutes because the planned work by the Company does not occur within the DMC development district. DOC Ex. 405 at 57 and AJH-29 (Heinen Direct) (MERC's Response to DOC IR No. 28).

342. For two reasons, it is possible that Company may have access to SIA funding for certain future work. First, the development plan and development district boundaries can be modified, as detailed in Minn. Stat. § 469.43, subds. 4 and 5, which allow for modification of the development plan and, conceivably, the development district. Without a modification to the DMC development boundaries, it is unclear how successful MERC's application[56] for SIA funding will be. DOC Ex. 405 at 57 (Heinen Direct).

343. Second, to the extent that the private spending threshold is met, the Company may have access to SIA funding for certain future work. Although the DMCC and City of

[56] MERC applied for SIA funds, requesting $5 million to aid in the construction of the Rochester project. DOC Ex. 405 at 56 (Heinen Direct) (*citing* MERC Ex. 5 at ASL-2 and ASL-3 (Lee Direct) (MERC Application for SIA funding).

Rochester have final say on which public infrastructure projects are eligible for funds, if MERC undertakes projects within the DMC development district boundaries, the Company may have access to 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 has remaining life, it would be reasonable and prudent for MERC to petition the DMCC for SIA funds, and unreasonable to require MERC ratepayers to pay for these costs when other means of recovery exist. DOC Ex. 405 at 57 (Heinen Direct).

C. Summary

344. The Department recommended, and the ALJ concurs that the Commission should find that, since the work by MERC does not occur in the development district defined in the DMC Statutes, it is unlikely that the proposed Project is considered a public infrastructure project for SIA funding purposes.

345. The Department further recommended, and the ALJ concurs that, because utility infrastructure is generally considered public infrastructure and it is meant to promote implementation of the DMC, the Commission should require MERC to petition the DMCC for SIA funds if future work by the Company occurs within the development district.

346. The Department also recommended that the Company include a discussion and supporting data, as part of its annual rider filing, detailing any utility work done in the previous year within the development district, the number of applications made to the DMCC, and the amount of state aid received. DOC Ex. 405 at 58 (Heinen Direct). The ALJ agrees.

V. FINDINGS

347. The ALJ finds the following:

A. MERC's Forecast and Proposed Need for this Project

348. 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. DOC Ex. 405 at 58-59 (Heinen Direct).

349. The Company's need projections are not unreasonable and likely represent an acceptable estimate of expected need for the Rochester Area. DOC Ex. 405 at 36 (Heinen Direct); DOC Ex. 406 at 1-3 (Heinen Rebuttal); DOC Ex. 407 at 6 (Heinen Surrebuttal).

B. Eligibility of this Project for NGEP Rider Recovery

350. The Project is NGEP rider eligible because Rochester and the surrounding area meet the definition of Minn. Stat. 216B.1638 of an unserved or inadequately served area eligible for rider recovery. DOC Ex. 405 at 59(Heinen Direct); DOC Ex. 410 at 3 (Heinen Summary).

351. For purposes of rider recovery, a soft cost cap for this Project of $44,006,607 ((DOC Ex. 405 at 59 (Heinen Direct); DOC Ex. 410 at 3 (Heinen Summary); DOC Ex. 407 at 15 (Heinen Surrebuttal)). Further, the reasonableness and prudency of costs in excess of $44,006,607 including the contingency factor can be considered when MERC proposes to recover the costs in base rates, where MERC will bear the burden of proving why it is reasonable to require MERC's ratepayers to pay for the higher costs. DOC Ex.405 at 43 (Heinen Direct); DOC Ex. 407 at 7 and 10 (Heinen Surrebuttal).

C. Methods to Mitigate Capacity Costs

352. The Project would likely result in temporary excess capacity costs that should be mitigated to the maximum reasonable extent (DOC Ex. 410 at 6 (Heinen Summary).

353. The Company has agreed to explore the capacity release market and to review its tariff books to determine whether changes should be made to facilitate the movement of customers from interruptible to firm service. DOC Ex. 410 at 6 (Heinen Summary).

354. MERC should reasonably pursue mitigation of costs for sales customers, including the use of long-term capacity release contracts,[57] assessment of the cost of capacity to interruptible customers, movement of customers to firm service, sales of supplies to electric generation customers to mitigate excess capacity costs (DOC Ex. 410 at 6 (Heinen Summary)) and through use of excess capacity to avoid purchasing other, more expensive, capacity to serve other parts of the MERC-NNG PGA system. DOC Ex. 405 at 60 (Heinen Direct).

D. Ratepayer Recovery

355. Both sales and transportation customers should pay for the Project. Further, since expanding the capacity of NNG's system makes it less likely, all else equal, that interruptible customers will be interrupted, the costs of the Project should be recovered from both firm and interruptible customers.

356. The Commission should require MERC to provide in future AAA filings and in the annual rider recovery filing in this docket, specific data for each capacity release associated with the Rochester Area over the most recent gas year (i.e., July through June). 1 Tr. at 20.

E. MERC's RFP Process

357. The Commission should determine 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. DOC Ex. 402 at 14 (Ryan Direct); DOC Ex. 404 at 3 (Ryan Surrebuttal); DOC Ex. 409 at 1 (Ryan Summary).

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[57] MERC agreed with the Department that MERC "will make every effort to obtain the best available contract terms for release of excess capacity." 1 Tr. at 20.

F. Rate Design and Apportionment of Revenue Responsibility

358. The Commission should require MERC to apportion at least 50 percent of the revenue deficiency to MERC's Rochester customers and the remaining amount to MERC's non-Rochester customers, after assigning costs to Rochester Public Utilities, and calculated on a per-therm basis for each group.

359. The Commission should approve the recovery of NNG pipeline capacity costs through MERC's NNG PGA. DOC Ex. 401 at 8-9 (Peirce Surrebuttal).

G. Funding from Other Sources

360. The Commission should find that, since the work being done by MERC does not occur with in the development district defined in the DMC Statutes, it is unlikely that the proposed Project is considered a public infrastructure project for SIA funding purposes.

361. Because utility infrastructure is generally considered public infrastructure and it is meant to promote implementation of the DMC, the Commission should require MERC to petition the DMCC for SIA funds if future work by the Company occurs within the development district.

H. Filing Requirements for Future Rate Cases or Regulatory Filings

362. The Commission should require MERC, in future AAA filings and in the annual rider recovery filing in this docket, to provide specific data, for each capacity release associated with the Rochester Area over the most recent gas year (*i.e.*, July through June).[58]

363. The Commission should require the Company to provide detailed analysis in its next general rate case regarding interruptible and transportation rates and whether the rate structures and design for these classes are appropriate given the impacts (*e.g.*, excess firm capacity, less chance of curtailment) associated with the proposed Project. DOC Ex. 407 at 21 (Heinen Surrebuttal).

364. MERC agreed at the evidentiary hearing with this recommendation regarding the analysis of interruptible and transportation rates in MERC's next rate case. 1 Tr. at 20.

365. The Commission should require the Company to include a discussion and supporting data, as part of its annual rider filing, detailing any utility work done in the previous year within the development district, the number of applications made to the DMCC, and the amount of state aid received. DOC Ex. 405 at 58 (Heinen Direct).

[58] MERC agrees to the recommendation. 1 Tr. at 20. The Department will review these releases at that time to determine whether the terms of the capacity release were reasonable based on market conditions.