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

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

MPUC Docket No. G011/GP-15-895
OAH Docket No. 68-2500-33101

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

PROPOSED FINDINGS OF FACT AND CONCLUSIONS OF LAW
OF THE OFFICE OF THE ATTORNEY GENERAL
RESIDENTIAL UTILITIES AND ANTITRUST DIVISION

October 25, 2016

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This matter came for evidentiary hearing before Administrative Law Judge ("ALJ") Jeanne Cochran on September 6 and 7, 2016, in the Small Hearing Room at the offices of the Minnesota Public Utilities Commission ("Commission") in St. Paul, MN. Pursuant to the ALJ's First Prehearing Order of March 9, 2016, the Office of the Attorney General – Residential Utilities and Antitrust Division ("OAG") files its Proposed Findings of Fact and Conclusions of Law.

PROCEDURAL BACKGROUND

This matter came for evidentiary hearing before Administrative Law Judge ("ALJ") Jeanne Cochrane from September 6, 2016 through September 7, 2016 in the Small Hearing Room at the offices of the Minnesota Public Utilities Commission ("Commission") in St. Paul, MN. Public hearings were held from July 11, 2016 through July 15, 2016. Post hearing briefs were filed on October 11, 2016, and responsive briefs were filed on October 25, 2016. The hearing record closed on October 25, 2016, following the receipt of the last responsive brief.

Michael C. Krikava and Kristin M. Stastny, Briggs and Morgan, P.A., appeared on behalf of the Applicant, Minnesota Energy Resources Corporation ("MERC" or "the Company").

Linda S. Jensen, Assistant Attorney General, appeared on behalf of the Minnesota Department of Commerce, Division of Energy Resources ("Department").

Ryan P. Barlow and Joseph Dammel, Assistant Attorneys General, appeared on behalf of the Office of the Attorney General – Residential Utilities and Antitrust Division ("OAG").

Eric F. Swanson, Winthrop & Weinstine, P.A., appeared on behalf of Northern Natural Gas ("Northern" or "NNG").

Andrew P. Moratzka and Emma J. Fazio, Stoel Rives LLP, appeared on behalf of Hibbing Taconite Company, ArcelorMittal USA's Minorca Mine, Northshore Mining Company, United Taconite, LLC, the Minntac and Keetac Mines of United States Steel Corporation, and USG Interiors, Inc., collectively known as the Super Large Gas Intervenors.

Robert Brill and Sundra Bender, staff of the Public Utilities Commission also participated in the hearing.

STATEMENT OF THE ISSUES

On October 26, 2015, MERC filed its Petition for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project.[1] On February 8, 2016, the Commission issued its Notice of and Order for Hearing referring the matter to the Office of the Administrative Hearings for contested case proceedings.[2] The Notice of and Order for Hearing set out the following issues to be addressed by all parties:[3]

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 recovery the Rochester Project costs from all of MERC's ratepayers?

[1] Ex. 1 (Petition).
[2] Notice of and Order for Hearing, at 8 (Feb. 8, 2016).
[3] *Id.* at 5.

a. If so, on what basis;
b. If not, what other allocation method would be more reasonable?

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

The Notice of and Order for Hearing noted that the Commission would defer its decision on the accuracy of MERC's revenue-deficiency calculation until a future rider filing.

Based on the evidence in the hearing record, the Administrative Law Judge makes the following:

FINDINGS OF FACT

I. SUMMARY OF PETITION.

1. On October 29, 2015, MERC filed a Petition for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project ("Rochester Project").[4]

2. The Petition was filed under the Natural Gas Extension Project ("NGEP") Rider Statute, Minnesota Statutes section 216B.1638.

3. The Petition sought evaluation and approval of its Rochester Project, which is designed to expand the capacity of the distribution system in and around the Rochester area along with a corresponding expansion of the interstate natural gas pipeline by NNG.

II. PARTIES TO THE PROCEEDING.

4. MERC is a local distribution company organized under the laws of the State of Delaware, authorized to do business in Minnesota, with its principle office located in Eagan, Minnesota. MERC provides natural gas service to approximately 230,000 customers in 52 counties and 184 communities in Minnesota, including the city of Rochester located in Olmstead County.

5. MERC is a subsidiary of WEC Energy Group, Inc. ("WEC"). MERC was previously owned by Integrys Energy Group, Inc. On June 29, 2015, WEC acquired Integrys and its subsidiaries, including MERC. WEC is now the corporate parent of MERC and several other natural gas and electric utilities in Wisconsin, Illinois, and Michigan.

6. The Department is responsible for enforcing the provisions of Minnesota Statutes chapters 216A and 216B, which provide for the regulation of utilities such as MERC. Department staff reviews the testimony and schedules filed by the utility and other parties to assure their accuracy and completeness, and files testimony and argument addressing the reasonableness of issues.

[4] Ex. 1 (Petition).

7. The OAG represents the interests of residential and small business customers in proceedings before the Commission. The OAG staff reviews the testimony and schedules filed by the Company and other parties and files testimony and argument addressing various issues.

8. NNG is the interstate natural gas supplier that provides service to MERC in the Rochester area. NNG is also the supplier that MERC has chosen to contract with to increase the supply of natural gas capacity.

9. The SLGI is comprised of some of the largest industrial customers of MERC in Minnesota. SLGI includes Hibbing Taconite Company, ArcelorMittal USA's Minorca Mine, Northshore Mining Company, United Taconite, LLC, the Minntac and Keetac Mines of United States Steel Corporation, and USG Interiors, Inc.

III. JURISDICTION

10. The Commission has general jurisdiction over MERC's rates under Minn. Stat. §§ 216B.01 and 216.03 (2016). While the Commission does not generally pre-approve utility investments, the Commission has specific jurisdiction over MERC's request for rider recovery under Minn. Stat. § 216B.1638.

11. The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48–.62 (2016) and Minn. R. 1400,5010–.8400 (2015).

IV. PROCEDURAL BACKGROUND

12. On October 29, 2015, MERC filed its Petition.

13. On November 3, 2015, the Commission issued a notice requesting comments on whether the matter should be referred to the Office of Administrative Hearings for a contested case proceeding, and other procedural questions. On November 25, 2015, MERC filed comments recommending that the Commission not refer the matter to the Office of Administrative Hearings. Also on November 25, 2015, the Department filed comments recommending that the Commission deny, without prejudice, MERC's petition and require MERC to refile the petition when complete. The Department also recommended that the Commission order a contested case if a party requests such a proceeding. Also on November 25, 2015, the OAG filed comments recommending that the Commission refer the matter to the Office of Administrative Hearings for a contested case proceeding.

14. On December 7, 2015, MERC filed reply comments and provided additional information in response to the comments of the Department and the OAG.

15. On December 24, 2015, the Department filed comments recommending that the Commission hold MERC's petition in abeyance until after the major policy and rate-design decisions were made in MERC's pending general rate case, Docket No. 15-736. The Department also recommended that the issues of the reasonableness of the Rochester Project, the cost allocations, and any other questions should be resolved in the general rate case.

16. On December 29, 2015, MERC filed responsive comments in which the Company agreed with the Department's suggestion to resolve issues related to the Rochester Project in MERC's general rate case.

17. On January 5, 2016, the OAG filed comments disagreeing with the agreement of MERC and the Department to change the scope of MERC's general rate case, which was filed on August 17, 2015, and in which Direct Testimony would be due on March 18, 2016.

18. The Commission held a hearing to consider the matter on January 14, 2016 and issued its Notice of and Order for Hearing on February 8, 2016. In its Order, the Commission accepted MERC's petition as substantially complete and referred the matter to the Office of Administrative Hearings for a contested case proceeding. The Commission moved all issues related to Rochester Phase II costs from the general rate case into this docket. The Commission directed the Administrative Law Judge to provide a report no later than November 30, 2016, to the extent practicable, requested that the Office of Administrative Hearings hold public hearings in MERC's service territory, and requested that the Office of Administrative Hearings add the City of Rochester, the Mayo Clinic, and the Destination Medical Center governing board to the service list.

19. In the Notice of and Order for Hearing, the Commission determined that the parties to the case included MERC, the Department, and the OAG. On February 2, 2016, NNG filed a petition to intervene.

20. On March 3, 2016, the Administrative Law Judge held a prehearing conference.

21. On March 7, 2016, the Administrative Law Judge issued the First Prehearing Order that granted the intervention request of NNG, set procedures for parties in the case, and established 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	July 11 – 15, 2016 (tentative)
All Parties' Rebuttal Testimony	July 28, 2016
All Parties' Surrebuttal Testimony	August 25, 2016
Prehearing Conference	September 1, at 1:30 p.m. at the MPUC offices
Evidentiary Hearings – St. Paul	September 6 – September 9, 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

22. Also on March 9, 2016, the Administrative Law Judge issued a Protective Order to address the filing and use of trade secret information.

23. On March 14, 2016, the Administrative Law Judge issued a Highly Sensitive Trade Secret Protective Order to address the filing and use of Highly Sensitive Trade Secret Information.

24. On March 15, 2016, MERC filed its Direct Testimony.

25. On April 19, 2016, the SLGI filed a petition to intervene.

26. On May 2, 2016, the Administrative Law Judge filed an Order granting SLGI's petition to intervene.

27. On July 1, 2016, the Department and the OAG each filed their Direct Testimony. NNG and SLGI did not file any testimony.

28. Public hearings were held according to the following schedule:

- Kahler Apache Hotel, Rochester, Minnesota, July 12, 2016, 1:00 p.m.
- Kahler Apache Hotel, Rochester, Minnesota, July 12, 2016, 6:00 p.m.
- Albert Lea City Hall, Albert Lea, Minnesota, July 13, 2016, 6:00 p.m.
- Steeple Center, Rosemount, Minnesota, July 14, 2016, 1:00 p.m.
- Cloquet City Hall, Cloquet, Minnesota, July 15, 2016, 1:00 p.m.

29. On July 28, 2016, MERC, the Department, and the OAG each filed their Rebuttal Testimony. NNG and SLGI did not file any testimony.

30. On August 25, 2016, MERC, the Department, and the OAG each filed their Surrebuttal testimony. NNG and SLGI did not file any testimony.

31. On September 1, 2016, the Administrative Law Judge convened a prehearing conference.

32. On September 6 to September 7, 2016, the evidentiary hearing was held in the Commission's small hearing room in St. Paul, Minnesota.

33. On October 11, 2016, MERC, the Department, the OAG, and the SLGI each filed their Initial Briefs.

34. On October 25, some parties filed their Reply Briefs and Proposed Findings of Fact and Conclusions of Law.

V. DESCRIPTION OF THE ROCHESTER PROJECT

35. According to MERC's Petition,[5] the Company no longer has sufficient natural gas supply to meet current or future peak demand in the Rochester area.[6] While MERC has sufficient supply to meet demands for natural gas on a normal day, the Company states that it does not have sufficient gas supply to satisfy demand on a Design Day, which predicts the peak demand for natural gas on the coldest possible day. For that reason, MERC states that it must take action to increase the supply of natural gas in the region. In its Petition, MERC clarifies that the Company seeks to increase natural gas supply in the region because it "now has a limited ability to provide firm and reliable natural gas service to new commercial and industrial customers."[7]

36. The Company states that the primary barrier to acquiring more natural gas capacity is that there is only one natural gas supplier in the region, Northern Natural Gas ("NNG"), and NNG's interstate transmission system is fully subscribed. In order for MERC to increase the amount of firm capacity it has available, new interstate capacity must be constructed by either NNG or a competing supplier.

37. To determine how much additional natural gas capacity would be necessary, MERC conducted a forecast. According to MERC, the historical average annual compound growth rate, which measures the total change over the time period, was 0.27 percent per year from 2007 to 2015.[8] The simple average annual growth rate year over year was 0.46 percent.[9] Using historical data as a basis, MERC estimates that peak demand in the Rochester area will grow by 1.5 percent per year from 2015 to 2042.[10] A growth rate of 1.5 percent per year results in a peak demand forecast of approximately 91,000 dekatherms per day ("Dth/day") in 2042.[11] To this figure, MERC added a 5 percent reserve margin, and then rounded up to reach 100,000 Dth/day.[12] MERC's current firm capacity in the Rochester area is approximately 55,000 Dth/day. As a result, to reach its forecasted peak demand estimate for 2042, MERC would have to nearly double its firm capacity by adding 45,000 Dth/day of incremental capacity.

38. Based on this forecast, MERC created and distributed a Request for Proposals ("RFP") requesting bids to provide 100,000 Dth/day of firm capacity to the Rochester area under two different scenarios.[13] The first scenario asked bidders to propose a new pipeline to deliver

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[5] Ex. 1, at 2 (Petition).
[6] For purposes of this case the Company has described the Rochester area as including Olmsted County and the communities of Kasson and Blooming Prairie. *Id.* at 20.
[7] *Id.* at 2.
[8] Ex. 11, at 6, Table 1 (Clabots Surrebuttal).
[9] Ex. 300, at 29 (Urban Amended and Corrected Direct). Amended and Corrected versions of Dr. Urban's testimony were filed by the Court Reporter after the evidentiary hearing as a result of an agreement by MERC to remove trade secret designations from the testimony. The versions in the record are marked as Amended to refer to the agreed-upon changes to Trade Secret designations, while Corrected to refer to corrections made in an errata filing on September 2, 2016.
[10] Ex. 9, at 8, Table 3 (Clabots Direct); Ex. 12, at 21, Table 1 (Mead Direct).
[11] Ex. 17, Sexton Direct, at 39.
[12] *Id.*
[13] *Id.* at 39 (Sexton Direct).

100,000 Dth/day, and the second scenario asked bidders to work with NNG to provide an incremental 45,000 Dth/day to the area.[14] MERC received responses to the RFP from three companies: NNG, Northern Borders Pipeline, and Twin Eagle.[15] After reviewing the bids, MERC proceeded to negotiate with NNG.

39. The negotiations resulted in a Precedent Agreement between MERC and NNG to upgrade NNG's infrastructure to provide 45,000 Dth/day of incremental capacity in the Rochester area. The Precedent Agreement was initially executed on October 26, 2015, and an Amended Precedent Agreement ("PA") was executed on March 30, 2016 to reflect a change in the proposed in-service date and associated cost increases.[16]

40. The primary feature of the PA will increase the natural gas capacity available to MERC in the Rochester area to 100,000 Dth/day for 25 years, for a cost of about $60 million.[17] MERC states that it was able to negotiate additional conditions that provide value to ratepayers. These include: 1) an agreement to fix the NNG rate at the current tariff maximum;[18] 2) approximately 8,000 Dth/day in additional capacity for thirty additional markets in Southeast Minnesota at NNG's maximum tariff rate; 3) the opportunity for MERC to use up to 20% of the entitlement designated for the Rochester area at other delivery points without giving up the fixed rate; 4) the opportunity for MERC to increase its capacity in the Rochester reason by an additional 2,000 Dth/day in every odd-numbered year during the length of the PA; and 5) the right for MERC to elect to extend the term of the PA an additional five years at discounted rates.[19]

41. In order to take advantage of this new natural gas capacity, MERC states that it must make upgrades to the distribution system in the Rochester area. The first phase of distribution upgrades is being resolved in MERC's pending rate case, and MERC seeks approval and recovery of costs for Phase II in this proceeding. The Rochester area currently uses two town border stations ("TBS"): 1D and 1B. Phase II will upgrade TBS 1D, and replace TBS 1B with a new TBS.[20] In addition, MERC will construct a new high-pressure distribution pipeline to interconnect the northern and southern portions of the distribution system.[21] These upgrades will "give[] MERC the ability to shift the supply of gas where it is needed on the distribution system within the Rochester area," for an estimated cost of $44 million.[22]

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[14] *Id.*
[15] *Id.* at 41.
[16] Ex. 306, Highly Sensitive Trade Secret Schedule JAU-7 (Urban Direct HSTS Schedules). The change in schedule was related to the time necessary to obtain regulatory approval from the Commission.
[17] Ex. 5, at 2 (Lee Direct).
[18] This condition would protect MERC and MERC's shareholders from rate increases that could result if NNG files a rate case or a modernization rider at the Federal Energy Regulatory Commission that would increase the tariffed rate.
[19] Ex. 17, at 46–50 (Sexton Direct).
[20] Ex. 7, at 3 (Lyle Direct).
[21] *Id.* at 3.
[22] *Id.* at 5.

42. Together, the costs of the NNG upgrades plus MERC's distribution upgrades are approximately $104 million. MERC seeks to recover these costs through a combination of riders and base rates. MERC proposes that the $60 million for NNG capacity costs be recovered through the NNG Purchased Gas Adjustment ("PGA") rider from all customers that are subject to the NNG-PGA. MERC proposes that up to 33 percent of the $44 million for Phase II distribution upgrades be recovered through a Natural Gas Extension Project ("NGEP") Rider authorized under Minnesota Statutes section 216B.1638, and the remaining costs through base rates when rate cases are filed.[23]

43. MERC has asked the Commission for at least three distinct determinations in this case. First, MERC requests an advance determination that the Rochester Project is reasonable, prudent, and necessary to provide service to its customers in the Rochester area. Second, MERC requests a determination that the Company may recover up to 33% of the Phase II costs of the Rochester Project through a new NGEP Rider under Minnesota Statutes section 216B.1638. Third, MERC requests a determination that its proposed cost allocations, which would collect the NNG costs from the NNG-PGA customers and the Phase II costs from all of MERC's customers, are reasonable.

VI. PRUDENCE, REASONABLENESS, AND NEED FOR THE ROCHESTER PROJECT.

44. The primary question in this matter is whether the Rochester Project that MERC has proposed is reasonable, prudent, and necessary to provide service to MERC's customers in the Rochester area.[24]

45. MERC's request for an advanced determination of prudence is unusual, however, because the Company does not normally need to obtain approval before proceeding with the project. There is an established process, under the Certificate of Need ("CN") statutes, for obtaining advanced approval of utility construction projects, but MERC is not required to obtain a CN because the Rochester Project is not a Large Energy Facility.[25] During the evidentiary hearing, MERC witness Ms. Lee confirmed that one reason the Company is seeking Commission agreement is that it is concerned about the risk of proceeding without regulatory approval.[26]

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[23] Ex. 5, at 17–18 (Lee Direct). In Ms. Lee's Direct Testimony, she states that the rate case revenue requirements would "include any deferred costs," but MERC has provided no further discussion of deferred costs in its filings. The Company has not taken the necessary step of requesting any deferred accounting, so the Commission should not consider any deferred accounting in this proceeding.

[24] Notice of and Order for Hearing, at 3 (Feb. 8, 2016).

[25] A natural gas pipeline is not classified as a Large Energy Facility unless it is 50 miles or more in length, and has a maximum pressure of 200 pounds per square inch. Minn. Stat. § 216B.2421 (2015). While the Rochester Project will transport natural gas at greater than 200 psi, there will be less than 50 miles of new construction.

[26] Tr. Evid. Hearing, Vol. 1, at 35:17-21 (Lee).

46. Ultimately, the question that must be answered is whether the utility has met its burden of "showing that it would be just and reasonable to include a particular utility expense in rates."[27]

A. Reserve Margins.

47. One way to analyze whether MERC's proposal to increase natural gas supplies is reasonable is to look at how much natural gas MERC proposes to obtain compared to how much natural gas MERC believes is necessary.[28] The measurement for this analysis is the "reserve margin."

48. The reserve margin measures how much capacity the Company has available compared to its Design Day (which is a measurement of peak demand on the coldest possible day). The reserve margin calculates the excess or shortfall of available capacity compared to the Design Day estimate of peak demand.

49. MERC states that its Design Day for the Rochester area was 60,929 Dth/day in the 2015/2016 heating season, and that its total available capacity is 55,169 Dth/day.[29] Using these figures, MERC calculates that it had a reserve margin of negative 9.5 percent during the 2015/2016 heating season.[30] Because of this shortfall, MERC reports, it must take action to increase the natural gas capacity available in the area.

50. MERC's plan to increase capacity will provide more capacity than is reasonable.

51. When the Project is initially complete, there will be a reserve margin of more than 50 percent in the Rochester area.[31] This means that MERC will have 50 percent more natural gas than is necessary to supply the highest possible demand, on the hypothetical coldest day. And, assuming that MERC's growth forecast is reasonable, MERC states that the reserve margin will continue to be more than 15 percent through the 2039/2040 heating season.[32] MERC witness Ms. Mead produced the following table in her Direct Testimony:

[27] Order Finding Imprudence, Denying Return on Cost Overruns, and Establishing LCM/EPU Allocation for Ratemaking Purposes, *In the Matter of a Commission Investigation into Xcel Energy's Monticello Life-Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, Docket No. E-002/CI-13-754, at 13 (May 8, 2015).
[28] In later sections, this Brief will address whether MERC's assumptions about the demand for natural gas are reasonable. In summary, they are not.
[29] Ex. 12, at 21, Table 1 (Mead Direct).
[30] *Id.*
[31] *Id.*
[32] *Id.*

Table 1 - Rochester Staging Plan (Dth/Day)

Winter Period	Rochester Design Day	Capacity 1D	Capacity 1B	Capacity New TBS	Total Capacity	Reserve Margin
2015/2016	60,929	36,707	18,462	0	55,169	-9.5%
2016/2017	61,842	36,707	18,462	0	55,169	-10.8%
2017/2018	62,770	36,707	18,462	0	55,169	-12.1%
2018/2019	63,712	47,207	18,462	0	65,669	3.1%
2019/2020	64,667	40,707	18,462	41,000	100,169	54.9%
2020/2021	65,637	40,707	18,462	41,000	100,169	52.6%
2021/2022	66,622	40,707	18,462	41,000	100,169	50.4%
2022/2023	67,621	40,707	18,462	41,000	100,169	48.1%
2023/2024	68,636	40,707	18,462	41,000	100,169	45.9%
2024/2025	69,665	40,707	18,462	41,000	100,169	43.8%
2025/2026	70,710	40,707	0	59,462	100,169	41.7%
2026/2027	71,771	40,707	0	59,462	100,169	39.6%
2027/2028	72,847	40,707	0	59,462	100,169	37.5%
2028/2029	73,940	40,707	0	59,462	100,169	35.5%
2029/2030	75,049	40,707	0	59,462	100,169	33.5%
2030/2031	76,175	40,707	0	59,462	100,169	31.5%
2031/2032	77,317	40,707	0	59,462	100,169	29.6%
2032/2033	78,477	40,707	0	59,462	100,169	27.6%
2033/2034	79,654	40,707	0	59,462	100,169	25.8%
2034/2035	80,849	40,707	0	59,462	100,169	23.9%
2035/2036	82,062	40,707	0	59,462	100,169	22.1%
2036/2037	83,293	40,707	0	59,462	100,169	20.3%
2037/2038	84,542	40,707	0	59,462	100,169	18.5%
2038/2039	85,810	40,707	0	59,462	100,169	16.7%
2039/2040	87,097	40,707	0	59,462	100,169	15.0%

MERC's table demonstrates that the Rochester Project will result in double digit reserve margins for more than twenty years. In 2040, MERC's customers will be paying for 15 percent more natural gas capacity than they will need at peak demand on the coldest possible day. And MERC's current customers will be paying for even *more* excess gas supply—MERC estimates that customers in the 2019/2020 heating season will be required to pay for 54.9 percent more natural gas than is necessary to serve peak demand.

52. These reserve margins are unreasonable according to industry standards described by MERC's independent consultant. According to Mr. Sexton, "[M]ost utility distribution companies maintain capacity reserve margins in the 3% to 7% range with targets near 5% with variances in reserve margin targets resulting from unique local conditions."[33] Mr. Sexton

[33] Ex. 17, at 10:14–16 (Sexton Direct).

described the 5 percent reserve margin as the "industry standard."[34] Based on this standard, MERC should be planning to add at least enough capacity to ensure it can maintain a reserve margin of approximately 5 percent in the Rochester area. Instead, MERC's plan will produce a reserve margin that is approximately ten times this industry standard at the outset, and as high as three times the industry standard in 25 years.

53. The OAG addressed three reasons that it argued made the Company's reserve margins unreasonable.

54. First, the OAG argued that ratepayers should not be required to fund the construction of utility infrastructure above and beyond what is reasonably necessary to provide service to firm customers.

55. Second, the OAG argued that excessive reserve margins create intergenerational inequities because current customers will be the ones who will pay for the majority of the Rochester Project, even though the Company has designed the Project to serve a group of customers far in the future.

56. Third, the OAG argued that the excess capacity created by the Rochester Project will provide a significant benefit for interruptible and transport customers due to a reduced risk for curtailment.[35]

57. The OAG then addressed how MERC planned its distribution system to meet Design Day firm load and how that planning process necessarily resulted in even higher levels of unused capacity for the majority of days throughout the year where demand does not reach Design Day levels. While not using this as an argument that MERC should not meet peak demand load, the OAG emphasized that on most days, the percentage of unused capacity would be higher than the Company's stated peak demand reserve margin.

58. MERC also suggested that its reserve margin should be analyzed in the context of the PA condition that allows MERC to deliver 20 percent of total capacity, or 20,000 Dth/day, in the Rochester area to other delivery points at the current tariff maximum. According to MERC, this condition means that the reserve margins are smaller, because the Company can move 20,000 Dth/day to other areas on its system. Using the Company's method, the reserve margin during the 2019/2020 heating season is only 23.0 percent (rather than 54.9 percent), because the Company would deliver 20,000 Dth/day to other delivery points.[36] The OAG addressed several problems with modifying the analysis in this way.

59. First, the OAG argued that already has the ability to deliver gas from the Rochester area to other points at its delivery system, regardless of this condition. What this condition provides is a guarantee about the price of doing so. And even that is not worth as

[34] *Id.* at 10:19–20.
[35] This concept will be discussed in more detail in Section III in the context of MERC's proposal for cost allocations.
[36] Ex. 12, at 23, Table 2 (Mead Direct).

much as it first appears, because the price that is guaranteed is the current *maximum price*.[37] The protection the condition provides is that the price of delivering Rochester capacity to other areas will not increase in the future if NNG files a rate case or a modernization rider.[38] The OAG argued that it makes little sense to reduce the reserve margin calculations by 20 percent as the result of a price guarantee. As MERC pointed out, the Company could deliver more than 20 percent of the Rochester capacity to other areas—it would just cost more.[39]

60. Second, the OAG argued that it is not reasonable to assume that reserve margins will be 20 percent lower because there does not appear to be any evidence in the record that other delivery points have demand for that much additional capacity.

61. Third, the OAG argued that there is no guarantee that MERC will be able to deliver the capacity where it wants on the days that it wants because it is likely that the times when additional capacity on the interstate system would be most useful coincides with times when the system has the greatest constraints.

62. In summary, the OAG argued that it is not reasonable to assume that 20 percent of the capacity in the Rochester area will always be used elsewhere. This condition does provide some value to ratepayers, but its value should not be overstated, and it should not be used to hide the large excess reserve margins that would result from the Rochester Project. If the Rochester Project moves forward, ratepayers will be required to pay for that capacity and it should be included in the reserve margin analysis used to determine whether the Rochester Project is prudent, reasonable, and necessary to provide service.

63. The reserve margins resulting from MERC's Rochester Project are not reasonable.

64. Ratepayers should not be subjected to costs above and beyond the costs that are necessary to provide firm customers with safe and reliable service.

65. Some investments are likely to be necessary to ensure safe and reliable service in the Rochester area, but MERC's plan goes so far above and beyond what is necessary to serve its customers that it is unreasonable. MERC's own witness testified that the industry standard for reserve margins is 5 percent—while there may be some reasonable allowances for instances in which large infrastructure investments are necessary, reasonable allowances do not extend to a double digit reserve margin that persists for more than twenty years.

B. RELIANCE ON THE LONG-TERM PEAK DEMAND FORECAST.

66. MERC performed a long-term peak demand forecast that it relied upon to determine the size of the Rochester Project.

[37] Ex. 13, at 14 (Mead Rebuttal).
[38] *Id.*
[39] *Id.* at 14:8–12.

67. The Company projected that peak firm system sales demand would be approximately 91,000 Dth/day, added a 5 percent reserve margin, and rounded up to the 100,000 Dth/day number that was used in its Request for Proposal ("RFP").

68. The Department acknowledged that it had not seen a natural gas growth forecast of this duration and noted that the longest natural gas utility forecast its witness had reviewed was 18 to 24 months. [40]

69. The Department also acknowledged that a shorter forecast has less forecasting risk than a long forecast. [41]

70. The OAG argued that it is not reasonable conduct a forecast and then make purchasing decisions as if the results of the forecast were guaranteed to come true. Such an outcome would force ratepayers to take on the risk that the dramatic growth it forecasts will not come to pass.

71. Due to the forecasting risk of such a long forecast, the Company's reliance on the results of its long-term forecast to determine the size of the Rochester Project was unreasonable.

C. MERC's Forecast For Growth In Peak Demand.

72. The OAG argued that there were flaws in MERC's peak demand forecast that led to an over-estimate of the demand growth rate.

73. The reasonableness of MERC's forecast is an important factor in determining the reasonableness and prudence of the Rochester Project because the Company determined the size of the Project, and the resulting cost, based on the forecast. The growth estimate produced by the forecast also impacts the excess reserve margins, or the amount of unnecessary supply that ratepayers would be obligated to pay for. As a result, the methodology and results of MERC's forecast are an important issue in the case.

74. MERC conducted a sales forecast using Ordinary Least Squares ("OLS") regression using historical data from January 2007 through July 2015 to produce a weather normalized estimate of sales growth from 2015 to 2025.[42] The Company states that the "general procedure was mainly utilizing a monthly customer count model and a use-per-customer model to derive total sales by class."[43] In the Petition, this process resulted in a sales growth rate of 1.6 percent per year from 2015 to 2025.[44] During the testimony process, MERC agreed with the OAG and the Department that the forecast should be conducted using weather data specific to the Rochester region, which reduced the annual sales growth rate from 2015 to 2025 to 1.5

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[40] Tr. Evid. Hearing, Vol. 2, at 25:1–2 (Heinen).
[41] Tr. Evid. Hearing, Vol. 2, at 24:7–12 (Heinen).
[42] Ex. 9, at 4 (Clabots Direct).
[43] Ex. 1, at 76 (Petition).
[44] Ex. 9, at 6 (Clabots Direct).

percent.[45] MERC then applied the ten year sales growth rate of 1.5 percent to its Design Day for a period of 25 years.

75. The OAG raised several concerns with MERC's forecasting methodology. First, MERC's growth rate is not supported by the historical data that is available. Second, MERC's customer count model is not reasonable. Third, MERC unreasonably assumed that Residential use-per-customer would remain constant for the entire 25-year time period. Fourth, MERC used "priori information" to create its forecast. Fifth, MERC assumes, without support, that it is reasonable to apply an estimate of *sales* growth to its Design Day, which measures peak demand. When these problems are addressed, the corrected forecast presents a much lower growth rate that does not support MERC's proposal to acquire 100,000 Dth/day of natural gas capacity for the Rochester region.

1. MERC's Forecasted Growth Rate Is Not Supported By Historical Data.

76. MERC forecasts that firm peak demand in the Rochester area will grow by 1.5 percent from 2015 to 2042. As discussed above, MERC constructed this forecast using historical sales data from 2007 to 2015. The OAG argued that the historical sales data simply does not support a growth rate of 1.5 percent, because the historical growth rate has been less than one-third of MERC's forecasted growth rate.

77. The OAG asked the Company to state the historical growth rate in an information request.[46] The results of that information request demonstrate that the historical average annual growth rate in the Rochester area has been 0.46 percent.

MERC Rochester Pipeline Expansion Project					
OAG-155 Question 2					
Rochester Weather Normalized Calendar Sales Data					
Units: Therms					
Weather Normalized Calendar Sales Data					
	Residential	**SC&I**	**LC&I**	**Total**	**% Chg**
2007	33,617,022	839,311	14,799,596	49,255,929	
2008	34,431,489	880,932	15,106,799	50,419,220	2.36%
2009	35,410,050	1,016,451	15,112,268	51,538,769	2.22%
2010	33,655,403	1,060,105	14,473,411	49,188,919	-4.56%
2011	35,161,983	1,220,915	15,686,775	52,069,673	5.86%
2012	35,287,597	1,058,178	16,434,231	52,780,006	1.36%
2013	35,619,126	1,367,791	16,601,029	53,587,946	1.53%
2014	38,121,516	1,691,545	17,872,702	57,685,764	7.65%
2015	33,297,050	1,182,199	15,838,890	50,318,139	-12.77%
Average Annual Percentage Change					0.46%

[45] *Id.*

[46] Dr. Urban introduced that Information Request into the record as Schedule JAU-10. As a result of a miscommunication between the OAG and MERC, the OAG updated Schedule JAU-10 in an errata filing to use weather normalized data. The schedules to Dr. Urban's Amended and Corrected Direct Testimony, which are filed as Exhibits 304, 305, and 306, include the correct, weather normalized version of this information.

This weather normalized data, provided by MERC, demonstrates that the average annual change in sales growth in the Rochester region is 0.46 percent. Over the entire time period, sales changed from 49,255,929 to 50,318,139—an increase of only 2.1 percent over an eight year period.

78. MERC estimates that its sales will grow by 1.5 percent each year for the next twenty five years. If spread over the same eight year period covered by historical data, MERC forecasts its sales will grow by 12.6 percent in the next eight years, even though sales have grown by only 2.1 percent over the last eight years.

79. It is not reasonable for the Company to conclude that historical data supports its forecasted estimate of growth in this case.

2. MERC's Customer Count Model Is Unreasonable.

80. According to MERC, the two main components of the forecast were the customer count model and the use-per-customer model.[47] The customer count model attempts to estimate how many customers MERC estimates will be in each class in a given year in the future.

81. MERC's customer count model estimates that its total number of customers in the Rochester area will grow by 2.0 percent each year.[48] But, according to MERC witness Mr. Clabots, the historical growth rate in customer count was 0.77 percent.[49] In other words, MERC is assuming that over the next 25 years the number of customers in the area will grow approximately 2.5 times faster than it has grown in the past. MERC's customer count model appears to be completely unreasonable compared to historical data.

82. Department witness Mr. Heinen also noticed that MERC's customer count estimates were higher than the population growth estimates provided by the Rochester-Olmsted Council of Governments ("ROCG").[50] While MERC estimates a 2 percent growth in customer counts, ROCG estimated population growth of only 1.5 percent.[51]

83. Mr. Heinen also compared MERC's estimated customer count growth to historical household data from the United States Census Bureau and the Minnesota State Demographic Center. Using historical data from Olmstead County, Mr. Heinen estimated that average household growth since 1990 is approximately 1.65 percent, with a noticable downward trend.[52] As Mr. Heinen testified, "the Company's Residential customer count projections assumed significant increases in population and household growth, above current conditions."[53]

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[47] Ex. 1, at 76 (Petition).
[48] Ex. 9, at 9, Table 5 (Clabots Direct).
[49] *Id.* at 10, Table 6. 0.77 = (0.91 + 0.91 + 0.73 + 0.37 + 0.58 + 0.99 +0.90) / 7
[50] Ex. 405, at 15–16 (Heinen Direct).
[51] *Id.*
[52] *Id.* at 17.
[53] *Id.* at 18.

84. Following his testimony regarding these concerns, Mr. Heinen conducted an alternate customer count forecast using an OLS regression.[54] The results of this analysis suggested a growth rate in customer counts of approximately 0.75 percent per year, which was significantly less than MERC's estimate.[55] OAG witness Dr. Urban reviewed Mr. Heinen's analysis and agreed that MERC had significantly over-estimated the customer counts that went into its forecast—and that, as a result, MERC's forecast would materially overstate growth in peak demand.[56]

85. In summary, both the OAG and the Department agree that MERC's customer count model overstates the customer counts that go into the forecast. As a result, MERC's customer count model is unreasonable.

3. MERC Unreasonably Assumes That Residential Use-Per-Customer Will Remain Constant.

86. MERC also utilized a use-per-customer model in its forecast.[57] The Company's use-per-customer assumed that Residential use-per-customer would remain constant for the next 25 years.

87. The OAG argued that this is an unreasonable assumption because use per customer has been trending downward recently as a result of energy conservation and efficiency improvements.

88. One modification suggested by OAG witness Dr. Urban was inclusion of a time trend variable for the Residential class.[58] MERC used this analytical tool in its use-per-customer model for the Small C&I customer class.[59]

89. The OAG argued that including a time trend variable in the regression analysis can be used to investigate whether there is a downward trend in residential use-per-customer, and whether the trend variable is a significant explanatory variable in the model.[60] In other words, a time trend variable can be added to the model to investigate whether residential use-per-customer is flat, as MERC assumes, or if there is a downward trend as observed in historical data.

90. OAG asked MERC to include a time trend variable in the residential use-per-customer model.[61] When that step was taken, the results of the residential use-per-customer model were reduced. While MERC estimated an average growth rate in residential sales of 1.87 percent without a time trend variable, including the time trend variable reduced the estimate to 1.34 percent—a reduction of 28 percent.

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[54] *Id.* at 26.
[55] *Id.* at 27.
[56] Ex. 307, at 4–5 (Urban Amended and Corrected Rebuttal).
[57] Ex. 1, at 76 (Petition).
[58] Ex. 300, at 30 (Urban Amended and Corrected Direct).
[59] Ex. 300, at 30 (Urban Amended and Corrected Direct).
[60] *See id.*
[61] Ex. 300, at 30 (Urban Amended and Corrected Direct); Ex. 304, JAU-15 (Urban Direct Schedules).

91. To verify whether the time trend was a significant explanatory variable, Dr. Urban asked MERC to calculate the p-value for the time trend coefficient.[62] The p-value measures the level of confidence as to whether an explanatory value is significant.[63] A p-value of zero indicates that the variable is "highly significant."[64] And, as MERC identified in its information request, the p-value for the time trend variable was 0.00 percent—indicating that its inclusion in the model is highly significant.[65]

92. In other words, including the time trend variable in the residential use-per-customer model is highly significant, and when the time trend variable is included in the model the growth rate result of the model is reduced by 28 percent.

93. Department witness Mr. Heinen also discussed the use of time trend variables. During the evidentiary hearing, Mr. Heinen pointed out that he included a time trend variable in his analysis of peak demand.[66] Mr. Heinen concluded that the time trend was not significant because the T-statistic was less than two, but greater than one.[67] What Mr. Heinen did not acknowledge, however, was that his T-statistic is based on a different model with different data. MERC's model estimates use-per-customer by customer class using sales data. Mr. Heinen's model estimates peak day use-per-customer, not sales use-per-customer. Further, Mr. Heinen's model is an estimate of all firm and non-firm customer data,[68] while the model discussed by the OAG and MERC is estimated by specific customer class. In other words, Mr. Heinen and Dr. Urban are conducting a different analysis, and Mr. Heinen's discussion does not rebut Dr. Urban's conclusion that a time trend variable is a significant explanatory variable for estimating residential use-per-customer. MERC admitted in its response to information requests that the time trend variable was a significant explanatory variable in the residential use-per-customer sales model, and Mr. Heinen's analysis on a different model does not change that fact.

94. MERC has not provided any explanation for why it would be reasonable to include a time trend variable for Small C&I customers, but exclude it for Residential customers.

95. MERC's residential use-per-customer model assumes that residential use will remain constant for the next 25 years. When the model is modified to include a time trend variable, which controls for the downward trend in use-per-customer, the variable is highly significant, and results in a growth rate that is 28 percent less than MERC's initial results.

96. This evidence clearly demonstrates that MERC's assumptions regarding the use-per-customer model are unreasonable.

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[62] Ex. 304, JAU-14 (Urban Direct Schedules).
[63] Tr. Evid. Hearing, Vol. 1, at 19–20 (Urban).
[64] Ex. 10, at 14:15 (Clabots Rebuttal).
[65] Ex. 304, JAU-14 (Urban Direct Schedules).
[66] Tr. Evid. Hearing, Vol. 2, at 63 (Heinen); *see also* Ex. 405, Schedule AJH-13 (Heinen Direct).
[67] Tr. Evid. Hearing, Vol. 2, at 63 (Heinen).
[68] *Id.* at 62:23–63:3 (Heinen).

4. MERC Unreasonably Uses "Priori Information" In Its Forecast.

97. The OAG argues that the use of *a priori* information is significant because it represents a departure from historical growth—the analyst uses his or her judgment to create expectations of future growth that is different from what would be supported by historical data.[69] While all forecasts involve the use of some judgment, when using *a priori* information it is essential to understand what the impact of that judgment has been in order to determine whether it is reasonable.

98. In its Petition, MERC stated, "The Rochester Residential and Small C&I customer count models are based on the "Priori Information" methodology. In other words, based on information that was gathered regarding expected future growth prior to preparing the model."[70] MERC clarified that the "information" that was gathered did not come from outside sources, but from MERC's employees: "The anticipated growth rate is based on information from MERC's Gas Planning Committee and from other MERC personnel who are directly involved with planning system needs resulting from Mayo Clinic's expansion plans."[71] Under the heading "*Data / Modeling Risks*," MERC states, "The assumptions made on Rochester Residential and SC&I are primarily based on the Mayo Clinic expansion, and the economic growth in the Rochester area. These assumptions do have significant impact on the forecasts."[72]

99. Based on these statements, the OAG attempted to determine what changes had resulted from the "Priori Information" that the Company used. The OAG sent the Company an information request requesting that the Company "reproduce MERC's growth estimates for the Rochester area without the DMC program."[73] Despite the fact that MERC had already filed documents stating that it had "based" its customer count numbers on "information from MERC's Gas Planning Committee," in its response to the Information Request the Company stated that the forecast "did not incorporate growth assumptions specific to the Destination Medical Center."[74] The Company agreed that it had used data from Moody's Analytics that "presumably reflect some assumptions about the impact of the DMC plan," but stated that it could not "determine the degree of that impact."[75] And later, in testimony and opening statements, MERC testified that it "used a priori or external information as a check on the reasonableness of its forecast assumptions."[76]

100. MERC initially provided signed documentation that it used "priori information" to adjust customer count figures, then contradicted that statement in an information request, then admitted that it did not know the impact of DMC-related priori information, and then testified that it used priori information only as a check on the reasonableness of its forecast. MERC has provided no clarification for these inconsistencies, but the simplest explanation is that MERC

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[69] Ex. 311, at 1 (Urban Amended Surrebuttal); Ex. 300, at 31 (Urban Amended and Corrected Direct).
[70] Ex. 1, at 77 (Petition).
[71] *Id.*
[72] *Id.* at 78.
[73] Ex. 311, at 1 (Urban Amended Surrebuttal); Ex. 313, JAU-SR-1 (Urban Surrebuttal Schedules).
[74] *Id.*
[75] *Id.*
[76] Ex. 26, at 2 (Clabots Opening Statement).

used priori information in exactly the way the Company described in its initial Petition to the Commission: as the basis for its Residential and Small C&I customer count models. This may be one reason that MERC's customer count models are so significantly overstated.

101. Department witness Mr. Heinen also discussed whether outside information from the DMC was included in MERC's forecast. In his Direct Testimony, Mr. Heinen stated that his customer count projections could be a "placeholder for the lack of inclusion of the DMC" in MERC's forecast.[77]

102. Mr. Heinen also testified that the customer count data on which he relied for his customer count modifications did account for the DMC. Specifically, Mr. Heinen stated that the information from the Rochester Olmsted Council of Governments "includes a job impacts from the Destination Medical Center [which] I would assume that they've incorporated impacts from the DMC into their population projections."[78]

103. While it is not unreasonable to incorporate some expectations about the DMC into the forecast, the Company's explanations of the *a priori* information it relied upon to adjust its forecast is not reasonable to support its forecast.

5. MERC Did Not Support The Reasonableness Of Applying A Sales Forecast To Design Day, Which Measures Peak Demand.

104. The OAG argued that MERC did not support its application of a sales forecast to its Design Day. MERC conducted a sales forecast and determined that retail sales would grow by 1.5 percent from 2015 to 2025.[79] MERC then applied this sales forecast to its measurement of peak demand—the Design Day. But it is not clear that annual retail sales and the Design Day, which measures peak demand on the coldest single day, are equivalent. MERC has not provided any testimony or evidence in the record to support its assumption that a 1.5 percent growth in sales would cause a 1.5 percent growth in peak demand. In fact, Mr. Heinen from the Department testified that "that's not a preferred method of doing it."[80]

105. While the record does not suggest any changes that could be made to correct this matter, the lack of evidentiary support for MERC's assumption goes to the weight that the forecast should receive, and the reasonableness of MERC's decision to rely on it so heavily when deciding the appropriate size of the Rochester Project.

6. The Corrected Forecast Does Not Support MERC's Proposal To Add 100,000 Dth/Day.

106. The OAG asked MERC to recreate its forecast with three changes.[81] First, the OAG asked MERC to use the Rochester specific weather data, which MERC had already agreed

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[77] Ex. 405, at 19 (Heinen Direct).
[78] *Id.* at 44 (Heinen).
[79] *Id.*
[80] Tr. Evid. Hearing, Vol. 2, at 59:18–19 (Heinen).
[81] Ex. 313, JAU-SR-2 (Urban Surrebuttal Schedules).

to. Second, the OAG asked MERC to use Mr. Heinen's customer count growth model. And third, the OAG asked MERC to incorporate a time trend variable in the residential use-per-customer model. With these changes, the forecast estimated growth of *negative* 0.1 percent—essentially, the forecast estimates that growth will be flat for the next ten years.

107. The OAG argued that this change has a significant impact on reserve margins—using the modified growth rate produced in this information request, the Rochester Project would continue to produce reserve margins in excess of 50 percent for the next 25 years:[82]

Rochester Area NNG Reserve Margin

	No Capacity to other TBSs		20% Capacity to other TBSs	
Winter Period	Company Forecast Reserve Margin	OAG Forecast Reserve Margin	Company Forecast Reserve Margin	OAG Forecast Reserve Margin
2015/2016	-12.79%	-12.79%	-12.79%	-12.79%
2016/2017	-14.08%	-12.71%	-14.08%	-12.71%
2017/2018	-15.35%	-12.63%	-15.35%	-12.63%
2018/2019	1.33%	6.25%	-2.25%	2.49%
2019/2020	40.95%	50.15%	29.19%	37.63%
2020/2021	38.87%	50.29%	27.28%	37.75%
2021/2022	36.81%	50.43%	25.40%	37.88%
2022/2023	34.79%	50.57%	23.55%	38.01%
2023/2024	32.80%	50.70%	21.72%	38.13%
2024/2025	30.84%	50.84%	19.93%	38.26%
2025/2026	28.90%	50.98%	18.15%	38.39%
2026/2027	27.00%	51.12%	16.41%	38.52%
2027/2028	25.12%	51.26%	14.69%	38.64%
2028/2029	23.27%	51.40%	12.99%	38.77%
2029/2030	21.45%	51.54%	11.32%	38.90%
2030/2031	19.66%	51.68%	9.68%	39.03%
2031/2032	17.89%	51.82%	8.06%	39.16%
2032/2033	16.15%	51.96%	6.46%	39.28%
2033/2034	14.43%	52.10%	4.89%	39.41%
2034/2035	12.74%	52.24%	3.34%	39.54%
2035/2036	11.07%	52.38%	1.81%	39.67%
2036/2037	9.43%	52.52%	0.30%	39.80%
2037/2038	7.81%	52.66%	-1.18%	39.93%
2038/2039	6.22%	52.80%	-2.64%	40.06%
2039/2040	4.65%	52.94%	-4.08%	40.18%
2040/2041	3.10%	53.08%	-5.50%	40.31%
2041/2042	1.58%	53.22%	-6.89%	40.44%
2042/2043	0.08%	53.36%	-8.27%	40.57%
2043/2044	-1.40%	53.50%	-9.62%	40.70%

This table demonstrates that when some of the problems in MERC's forecasting methodology are controlled, the unreasonable size of the Rochester Project becomes an even bigger problem. Even when assuming that the reserve margin should be reduced to account for 20 percent of capacity delivered to alternate points, a reserve margin of more than 40 percent would persist for more than 25 years.

[82] Ex. 311, at 4, Table 2 (Urban Amended Surrebuttal).

108. In the Information Request where MERC discussed the new forecast, MERC raised concerns about the modified forecast. Primarily, MERC states that it "has concerns with just adding a trend variable in isolation of other adjustments or variables," because "[c]hanging variables in isolation risks inconsistent and potentially skewed results."[83] As discussed above, though, MERC ignores the fact that the Company chose to include a time trend variable for Small C&I customers, but then chose not to include one for Residential customers. The OAG raised this issue in Dr. Urban's Direct Testimony[84]—and the Company has still provided no reason that it would be reasonable to add a trend variable for one group of customers, but not for another.

109. Second, MERC states that it "took an extra step" and replaced the 2015 forecast with 2015 weather normalized actual sales.[85] The OAG argued that it was inappropriate to replace actual 2015 data in the forecast estimate and cited a lack of explanation from the Company as to why it would be an appropriate modeling technique to do so. The OAG also pointed out that the result of swapping forecasted 2015 data with actual 2015 data is a growth rate of 1.1 percent—nearly thirty percent lower than MERC's initial growth rate.[86] In other words, even if the modified forecast is changed in the manner proposed by MERC, it still results in a growth rate that is significantly less than the growth rate that MERC uses to justify the Rochester Project.

110. Dr. Urban has raised significant concerns about the assumptions that went into MERC's forecast. When those concerns are addressed to create a modified forecast, the result is a growth rate somewhere between 50 percent and 100 percent less than MERC's forecast.

111. Dr. Urban's analysis demonstrates that MERC's forecast overstates the growth in peak demand, and also demonstrates that the magnitude of MERC's errors are significant.

7. MERC's Forecast Significantly Overestimates The Growth Of Peak Demand In The Rochester Area.

112. The OAG has demonstrated that the combination of all of the problems discussed above clearly demonstrate that MERC's forecast overestimates the growth in peak demand for Rochester area customers. When some of those problems are controlled, the changes in growth rate lead to reserve margins greater than 50 percent for decades.

113. MERC's forecast model is flawed, and MERC's decision to select the size of the Rochester Project based exclusively on that forecast is unreasonable.

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[83] *Id.*
[84] Ex. 300, at 30:8–10 (Urban Amended and Corrected Direct) ("Unlike the small commercial and industrial average use model, the residential average use model does not include a time trend variable.").
[85] Ex. 313, JAU-SR-2 (Urban Surrebuttal Schedules).
[86] Ex. 11, at 13 (Clabots Surrebuttal).

114. The modified growth rates that result from correcting the problems with MERC's forecast demonstrate that a more moderate, phased or incremental proposal would be a more prudent, reasonable, and appropriate way to meet demand.

115. The Project that MERC has proposed is excessive, and would result in unreasonable costs being recovered from captive ratepayers.

D. MERC's RFP Was Not Designed To Consider All Alternatives.

116. MERC's RFP was issued on December 31, 2014.[87] In the RFP, MERC sought bids for two different options to increase the available natural gas capacity in the Rochester region. The first option would be to provide 100,000 Dth/day of firm capacity at new TBS on the northwest side of Rochester, while the second option would be to work with NNG to provide 45,000 Dth/day of incremental capacity for a total of 100,000 Dth/day of firm capacity. Both options had the same goal—provide 100,000 Dth/day of firm capacity to the Rochester area.

117. In its initial Petition, MERC did not provide any explanation as to why the RFP was targeted to 100,000 Dth/day. The first time the Company addressed the issue was in the Direct Testimony of Mr. Sexton, as follows:

> **Q. WHY DID MERC REQUEST A PIPELINE DESIGN WITH A CAPACITY OF 100,000 DTH/DAY?**
>
> A. Utilizing its current projected 1.50% per year annual growth rate in the Rochester area as supported by MERC witness Mr. David Clabots, MERC projects that firm system sales demand in that part of the State will be slightly greater than 91,000 Dth/day at the end of the twenty-fie year term in the year 2042. With a 5% reserve margin added, this converts to a capacity requirement of about 96,000 Dth/day. This number was then rounded up to 100,000 Dth/day for use in the RFP.[88]

According to Mr. Sexton, MERC requested a pipeline design with a capacity of 100,000 Dth/day because that was the result of MERC's forecast.

118. The OAG argued that designing the RFP to obtain bids for 100,000 Dth/day is a problem because it means that MERC relied exclusively on the results of its forecast to determine how large the Rochester Project should be. The OAG further argued that the record demonstrates that MERC flatly rejected some responses to the RFP because they did not satisfy the demand from the forecast. Mr. Sexton noted that Phased Proposal 2.3 was rejected because it did not "provide MERC with sufficient capacity to meet long-term demand" as shown in

[87] Ex. 316, Schedule JAU-4 (Urban Direct Schedules HSTS).
[88] Ex. 17, at 39:21–40:6 (Sexton Direct).

MERC's forecast.[89] MERC effectively decided that its only option was to obtain exactly 100,000 Dth/day, simply because that was the result of its forecast.

119. In the Company's initial Petition, their description of the sales forecasting methodology included a section titled "*Data / Modeling Risks*."[90] In that section, MERC states:

> The assumptions made on Rochester Residential and SC&I are primarily based on the Mayo Clinic expansion, and the economic growth in the Rochester area. These assumptions do have significant impact on the forecasts.
>
> The risk of unanticipated national economic weakness could have adverse effects on the Minnesota economy, and impact sector growth.
>
> Further, unanticipated milder weather conditions, increases in energy prices, and downward trends in Moody's Analytics' economic and demographic forecasts would adversely impact the forecast of increased future sales growth.[91]

120. The OAG argued that MERC was also warned of forecasting risk by NNG, in the interstate pipeline company's response to the RFP. Specifically, NNG explained that some of its phased in proposals would provide benefits to ratepayers even though they did not immediately provide 100,000 Dth/day of capacity. According to NNG, these proposals would "eliminate the need for MERC to make construction decisions now based on forecast growth requirements that may occur over a 20-year or longer time period."[92] NNG noted that this approach would "reduce[] the risk to MERC's customers for costs associated with overbuilding facilities for forecasts of unknown growth."[93] NNG pointed out that a smaller or phased option could "reduce[] risk for MERC and its customers by ensuring that it does not overbuild pipeline facilities before they are required while maintaining the ability to serve the growth needs of the community," and that the advantage would "protect[] customers from upfront costs and potential rate shock due to a large single build-out of capacity when the capacity may not be needed until a future time period."[94]

121. After the OAG raised its concerns about the design of MERC's RFP, the Company came up with new arguments in an attempt to justify the large size of the RFP. In its Rebuttal Testimony, MERC argued for the first time that the RFP needed to be designed at a

[89] Ex. 19, at 13 (Sexton Direct).
[90] Ex. 1, at 78 (Petition).
[91] *Id.*
[92] Ex. 300, at 18–19 (Urban Amended and Corrected Direct); *see also* Ex. 306, Schedule JAU-5 (Urban Direct Schedules HSTS). NNG's response to the RFP is marked as Highly Sensitive Trade Secret, but MERC agreed to remove the designation for the quoted sections, which are contained in Dr. Urban's Amended and Corrected Direct Testimony.
[93] *Id.*
[94] *Id.*

large size in order to attract competitive bids from pipeline companies other than NNG.[95] According to Mr. Sexton, permitting smaller responses to the RFP "would not have fostered the competitive environment."[96] This argument is suspect, however, because MERC did not mention the concept of a "competitive environment" until the RFP was challenged.

122. The OAG argued that the bids received by parties other than NNG were not competitive in comparison to the bids received by NNG.

123. The OAG argued that an RFP that was more open-ended could have achieved more competitive results. If MERC designed an RFP that accepted bids "up to 100,000 Dth/day," then the Company may have received bids from NNG's competitors, in addition to bids that would allow the Company to account for forecasting risk by considering smaller projects or phased projects.

E. MERC's Analysis Of The RFP Was Flawed.

124. The OAG argued that the primary problem with MERC's analysis of the RFP is that its analysis of the responses was not sufficiently rigorous to justify the Project that has been proposed.

1. MERC's Analysis Of The RFP Responses Was Insufficiently Rigorous.

125. The OAG argued that the information that MERC provided regarding its analysis of RFP responses is not sufficient to demonstrate a complete analysis of the responses to the RFP for several reasons.

126. First, MERC does not provide any narrative explanation of its process. Instead, MERC's analysis comprises a single page spreadsheet without explanation of the weighting, scores, or methodology.[97]

127. Second, MERC's analysis addresses only four proposals, despite the fact that NNG provided more than ten proposals. Each of those proposals included detailed descriptions for different projects, at different levels of cost and benefit for ratepayers.

128. Third, MERC did not even select the bid that received the highest score and provided no discussion as to why this was a reasonable outcome.

129. In conclusion, the OAG has demonstrated that MERC has not provided evidence that it has conducted the type of analysis that should be required in order to get approval of such a large project.

[95] Ex. 19, at 6 (Sexton Rebuttal); Ex. 14, at 12 (Mead Rebuttal).
[96] Ex. 19, at 6 (Sexton Rebuttal).
[97] *Id.* The following information is all drawn from this spreadsheet.

2. MERC Did Not Obtain Independent Review Of Its Analysis Until After All Of The Decisions Were Made.

130. The OAG argued that the independent review of the RFP, which was conducted after all of the important decisions had been made, provided little to no value to the determination of reasonableness at issue in this case. The OAG argued that the analysis of Mr. Sexton provided little value because it was conducted after the Precedent Agreement had been executed, Mr. Sexton was aware of the Company's final decision when he began his analysis, and he did not review all RFP responses.

3. MERC Did Not Provide An Analysis Of Distribution System Costs.

131. The OAG argued that MERC did not provide an estimate of the distribution costs for a more moderate interstate capacity solution.

132. The information in the record indicates that MERC estimates its costs to upgrade the distribution system will be $44 million. But there is no information about how much distribution upgrades would have cost if MERC had proceeded with a more moderate Rochester Project. If the Company were planning to increase natural gas capacity by 20,000 Dth/day, instead of 45,000 Dth/day, it is entirely possible that the cost of upgrading the distribution system to accept the new capacity would be similarly reduced. But MERC has not provided any information of that nature.

133. The particular configuration of the distribution system led MERC to reject several bids. For example, Mr. Sexton testified that NNG Proposal 2.2 and 2.3 were rejected because they did not deliver incremental capacity to the correct TBSs at the correct pressures.[98] As such, they did not "conform to the RFP requirements, did not meet operational requirements, and [were] not evaluated further."[99] But, as Ms. Lyle agreed, the distribution upgrades the Company plans to build will allow the Company to "move [the gas] wherever [MERC] need[s] it," once the interconnection is complete.[100]

134. The facts in the record indicate that the planned distribution upgrades would allow MERC to accept gas anywhere on the system and move it where it was needed, but that MERC still rejected at least one proposal because it would not bring gas to the right place.

135. It is likely that each of the proposals for the Rochester Project would have required a different distribution configuration. It is also likely that MERC could have chosen different investments to upgrade the distribution system in the Rochester area. But MERC has either not conducted any analysis on the different options, or has declined to provide it in this case. As a result, it is not possible to determine whether any of the different interstate pipeline proposals could have been selected to minimize distribution costs.

[98] Ex. 19, at 11 (Sexton Direct).
[99] Ex. 19, at 11 (Sexton Direct).
[100] Tr. Evid. Hearing, Vol. 1, at 62:4–7 (Lyle).

4. MERC Has Misrepresented The Facts Regarding The Responses To The RFP.

136. The OAG argued that there are several instances in which the statements MERC has made about the RFP are not consistent with the facts in the record.

137. The first time MERC discussed the responses to the RFP was in its initial Petition. In the Petition, MERC stated that "NNG responded with two proposals. One was to build a new 600 psig transmission pipeline in the Rochester area. The other proposal was to upgrade the capacity of its existing area pipeline system to 600 psig."[101] The record indicates that NNG actually provided as many as thirteen different proposals. NNG also made clear that each of the proposals was only a starting point for negotiations.[102]

138. Dr. Urban also identified inconsistencies in MERC's Direct Testimony. In her Direct Testimony, Ms. Mead testified that, "NNG advised us that the only available alternative was to make a major expansion of the pipeline system into the Rochester area. This proposal, while larger than we needed in the near term, compared favorably against other proposals that would have required an equivalent major expansion by building a new pipeline into the area."[103] As Dr. Urban pointed out, though, Ms. Mead's statement is "directly contradictory to NNG's response to the RFP."[104] Dr. Urban noted,

> NNG went out of its way to propose phased proposals that would *not* have required 'major expansion of the pipeline' in the short term, as Ms. Mead suggests. In fact, NNG took pains to point out that a phased approach could 'eliminate the need for MERC to make construction decisions now based on forecast growth requirements that may occur over a 20-year or longer time period,' 'reduce[] the risk to MERC's customers for costs associated with overbuilding facilities for forecasts of unknown growth,' and 'protect customers from upfront costs and potential rate shock due to a large single build-out of capacity when they capacity may not be needed until a future time period.'[105]

In light of these warnings by NNG, Ms. Mead's statement that the "only available alternative was to make a major expansion" appears disingenuous at best.

139. The OAG notes that the Company did not provide either the Precedent Agreement, the RFP or the responses to the RFP until they were demanded in discovery. Dr. Urban pointed out that, "It is unclear [] how the Commission could be expected to approve of MERC's proposal without a thorough understanding of how MERC's RFP was designed and

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[101] Ex. 1, at 26 (Petition).
[102] Ex. 306, Schedule 5 (Urban Direct Schedules HSTS).
[103] Ex. 12, at 27 (Mead Direct).
[104] Ex. 300, at 50 (Urban Amended and Corrected Direct).
[105] *Id.*

what responses it received."[106] During the evidentiary hearing, MERC witness Ms. Lee confirmed that the Company had asked the Commission for approval of this $100 million infrastructure project without providing the Precedent Agreement, the text of the RFP, or the responses to the RFP in either its initial petition or its direct testimony.[107]

140. While the OAG and the Department eventually made sure that this information was made part of the record, the Company's lack of transparency along with repeated misrepresentations about the responses it received to the RFP, reflect poorly on MERC's decision-making process.

5. The Department's Agreement With The RFP should Be Given Little Weight Because The Department Did Not Actually Analyze The Responses To The RFP.

141. In his Direct Testimony, Department witness Mr. Ryan testified that his responsibility was to review the RFP conducted by MERC, and that the purpose of his review was to determine "a) whether MERC selected the least cost alternative to meet the proposed need . . . and b) whether MERC met the statutory requirement to show that 'project costs are reasonable and prudently incurred.'"[108] Mr. Ryan testified that he had "access to the RFP responses," and "review[ed] MERC's comparative evaluation of the competitive bids."[109] Based on this, Mr. Ryan concluded that MERC's RFP process was fair and reasonable.[110]

142. During the evidentiary hearing, though, Mr. Ryan admitted that he did not actually perform any analysis of the responses to the RFP. Specifically, Mr. Ryan confirmed that he did not do his own independent analysis of the bids.[111] Instead, all that Mr. Ryan did was "read the RFP responses and [] review MERC's analysis of them."[112] Further, Mr. Ryan admitted that he was not sure where or how MERC was deciding what scores different bids received in the comparative analysis.[113]

143. Mr. Ryan also stated in his Opening Statement that he did not "address[] the size and timing of the project."[114]

144. The OAG argued that Mr. Ryan did not consider whether MERC's proposal is the proper size—the single most important factor in the reasonableness of the project. The lack of analysis was not limited to Mr. Ryan. Department witness Mr. Heinen also confirmed during the

[106] *Id.* at 15–16.
[107] Tr. Evid. Hearing, Vol. 1, at 28–29 (Lee).
[108] Ex. 402, at 2 (Ryan Direct).
[109] *Id.* at 9–10.
[110] *Id.* at 14.
[111] Tr. Evid. Hearing, Vol. 1, at 213 (Ryan).
[112] *Id.* at 214:2–6 (Ryan).
[113] *Id.* at 217:2–3 (Ryan).
[114] Ex. 409 (Ryan Opening Statement).

evidentiary hearing that he did not do a detailed analysis of the RFP, because it was Mr. Ryan's responsibility.[115]

145. The Department's concurrence with MERC's RFP and the RFP process should be given little weight in this proceeding, because the Department did not conduct its own analysis of either the RFP or the RFP responses.

6. MERC's Analysis Of The RFP Was Not Sufficient.

146. The facts in the record demonstrate that MERC did not conduct a sufficient analysis of the responses it received to the RFP. The independent analysis MERC obtained came too late to be useful, and under questionable circumstances. The combination of these concerns, and the others discussed above, indicates that MERC's analysis of the RFP is not sufficient to support the direction it chose for the Rochester Project.

F. MERC'S DECISION TO FOCUS ON UP-FRONT PROJECTS INSTEAD OF PHASED OR INCREMENTAL PROJECTS WAS NOT REASONABLE.

147. The OAG argued that one consequence of all of these problems with MERC's analysis of the RFP is that the Company did not give sufficient consideration to phased proposals that could have provided significant protections for ratepayers. MERC was presented with multiple phased proposals, but did not give them any serious consideration because of the Company's single-minded focus on only pursuing options that would immediately meet their long-term demand forecast.

148. The record demonstrates that these proposals could have provided ratepayers with significant benefits, but that MERC discarded them to focus on up-front proposals that will lead to overbuilding infrastructure, intergenerational inequities, and excess supply that will provide unreasonable levels of benefit to interruptible and transportation customers.

1. Phased Proposals Could Have Provided Significant Protections For Ratepayers.

149. As discussed above, one of the primary problems with the Rochester Project, as demonstrated by the OAG, is that MERC is proposing to acquire more capacity than is necessary. The OAG suggested that one way to deal with problems related to the timing of capacity additions would be to phase capacity additions in over time, or to add capacity incrementally.

150. The bid responses from NNG provide a list of ratepayer protections that could have resulted from a phased or incremental approach.

151. These descriptions lead the OAG to identify three important benefits that ratepayers could have obtained from a phased proposal. First, some of the proposals that NNG made would have allowed MERC the *option* of future capacity additions when they were needed,

[115] Tr. Evid. Hearing, Vol. 2, at 46–47 (Heinen).

without any obligation to do so if the need did not materialize. This would obviously insulate ratepayers from a significant amount of forecasting risk. In a phased proposal without obligation for future upgrades, ratepayers are not required to pay for capacity additions if the forecasted levels of growth do not materialize. And, if the forecasted growth *does* materialize, the utility has a plan in place to address it. The benefits of this approach are readily apparent.

152. Second, a phased or incremental proposal would more closely link the timing of when the costs of a project are paid by ratepayers to when the infrastructure is useful to ratepayers. In other words, some of the costs for a phased or incremental proposal would be incurred later. This would be more equitable because current ratepayers would be shouldering less of the burden required to provide service for ratepayers who might need the infrastructure upgrades in twenty or thirty years.

153. Third, because a phased in proposal will not result in such high reserve margins there would be less problems with ensuring that costs are shared equitably between all customers. As discussed in more detail in Section III, the extremely high reserve margins that would result from MERC's proposal would provide significant benefits to interruptible and transportation customers, but not all of those customers would share fully in the costs. A phased proposal could reduce these equity complications by reducing the reserve margins created up-front while still allowing MERC to pursue further upgrades in the future if demand grows as the Company predicts.

154. Several of the proposals NNG offered to MERC would have provided these benefits.

2. MERC Received Multiple Phased Proposals In Response To The RFP.

155. In response to the RFP, NNG provided multiple phased proposals that would have provided these benefits to ratepayers. Phased Proposal 2.3 would have increased capacity in the Rochester area by 10,000 Dth/day immediately, and then permitted MERC to add another 35,000 Dth/day in the future when growth materializes.[116]

156. Phased Proposal 4.1 would have increased capacity by approximately 17,669 Dth/day up-front, and given MERC the option to add an additional 27,331 Dth/day in the future when growth materializes.[117]

157. Phased Proposal 4.2 would have also increased capacity by approximately 17,669 Dth/day up-front, and given MERC the option to add an additional 27,331 Dth/day in the future, for a total of 100,000 Dth/day.[118] As compared to Phased Proposal 4.1, this proposal would install a compressor earlier in the process, which would be more efficient and permit long-term cost reductions in return for greater up-front costs.[119]

[116] Ex. 303, at 22 (Urban Amended and Corrected HSTS Direct).
[117] *Id.* at 23.
[118] *Id.* at 24.
[119] *Id.*

158. These Phased Proposals would have allowed MERC to address short term needs, with no obligation to pursue deferred upgrades.

159. As discussed above, the options to defer, or possibly terminate, future capacity growth would provide significant value for ratepayers. First, deferring some of the capacity would mean that the initial cost to ratepayers would be less burdensome. Second, deferring some of the capacity, and thus the cost, to the future would more closely tie the costs to the ratepayers who may need the facilities. Third, the option to defer or terminate the project would remove a significant portion of the forecasting risk from both ratepayers *and* shareholders, because the Company would have no obligation to move forward if growth does not materialize. On top of these benefits, it is important to note that the estimated costs for both Phased Proposal 4.1 and Phased Proposal 4.2 are comparable to the cost of the Rochester Project that MERC has proposed.

160. The information in the record shows that by choosing one of these Phased Proposals, MERC could have obtained these benefits and protected ratepayers from forecasting risk, without significant additional expenditures.

3. MERC Has Not Provided A Reasonable Justification For Failing To Give Serious Consideration To The Phased Proposals.

161. The record in this proceeding demonstrates that MERC did not give any serious consideration to the benefits that ratepayers could have obtained from a phased proposal.

162. NNG also described the benefits of phased proposals at length in its response to the RFP. Despite being aware of these benefits, MERC negotiated a PA that does not mitigate forecasting risk or reserve margin problems like the Phased Proposals provided by NNG.

163. MERC did not provide clear reasons that it did move forward with a Phased Proposal at the outset of its case, but later attempted to raise a series of arguments as to why its decision was reasonable. None of them hold up under scrutiny.

a. MERC did not conduct a reasonable analysis to justify its decision to pursue an up-front project instead of a phased or incremental approach.

164. The primary reason that MERC claims that it was reasonable for the Company to focus on an up-front project because it would have cost more for the Company to obtain the same amount of capacity in an incremental manner.[120]

165. To support this claim, MERC relies upon a "good faith estimate" of the costs of adding 100,000 Dth/day of capacity in an incremental capacity that was conducted by their independent consultant, Mr. Sexton.[121] According to Mr. Sexton, the Net-Present-Value ("NPV") cost of obtaining 30,000 Dth/day in incremental capacity would actually be $1 million greater

[120] Ex. 19, at 6–7, 12 (Mead Rebuttal).
[121] *Id.* at 7.

than the NPV cost of obtaining 45,000 Dth/day from the PA.[122] The Company states that "an incremental or smaller capacity project would result in greater costs for lower capacity volumes."[123] The Department, through its witness Mr. Heinen, appears to be convinced by MERC's analysis.

166. The OAG disputed this claim by the Company. In conducting its "analysis" of more moderate incremental or phased projects, MERC asked its consultant to conduct a "good faith estimate" of the costs of adding new capacity. But Mr. Sexton's estimates are not valid when compared to the results of the competitive bidding process that was conducted.

167. The evidence demonstrates that there were multiple phased proposals that were cost-competitive with the PA that was negotiated, even assuming that the deferred costs ultimately became necessary. And the phased projects could have provided the additional benefits if the deferred costs were ultimately not necessary—in that instance, the costs for the phased proposal could end up being significantly *less* than the cost of the PA.

b. MERC's claim that it had to pursue a large project in order to attract competing bids is not reasonable.

168. MERC also argues that it was necessary to pursue a large, up-front project because an RFP that permitted smaller bids would "not have attracted any non-incumbent third party service providers to submit proposals."[124]

169. The OAG argued that MERC's explanation regarding why it had to pursue a large project was not reasonable.

170. First, MERC ignores the fact that it could have designed an RFP that allowed for both large bids and smaller bids. That would have allowed competing pipelines to propose large projects that could take advantage of economies of scale to justify significant new pipeline investments, but it also would have allowed bidders to propose incremental or phased proposals that could have been analyzed to determine the proposal that provided the most benefits and protections to ratepayers.

171. Second, MERC ignores the fact that its RFP did not actually result in competitive bids from competing suppliers. As pointed out above, the bids from third parties were not competitive compared to the bids from NNG. In other words, the RFP process was not really competitive at all.

172. Third, MERC ignores the fact that it did actually receive bids for more moderate phased projects that could have provided significant protections to ratepayers. While the idea of an RFP large enough to allow competition is attractive, it does not justify ignoring phased or

[122] *Id.*
[123] *Id.*
[124] Ex. 13, at 12 (Mead Rebuttal).

incremental approaches when those options were already on the table regardless of how the RFP was designed.

c. MERC's argument regarding additional negotiated conditions is not relevant to the decision to focus on an up-front project.

173. MERC claims that it was reasonable to move forward with an up-front project only, rather than a phased or incremental project, because the PA included fixed-rate conditions from NNG, which were not included in the phased proposals.[125] The PA includes conditions that the capacity rates paid to NNG will be set at the current tariff maximum, even if NNG's tariff rates are increased in the future as a result of a FERC rate case or a modernization rider proposal.[126]

174. The OAG argued that MERC did not acknowledge that the fixed rate conditions were not included in any of the initial proposals from NNG. Instead, they were conditions that MERC was able to obtain through negotiation with its supplier. Mr. Ryan, for the Department, agreed during the evidentiary hearing that there does not appear to be any reason that MERC could not have requested the same new conditions in concert with a phased proposal.[127]

175. It is also clear that NNG went out of its way to make clear that the proposals in its response to the RFP were not exhaustive and that the supplier was open to discussing different conditions if MERC was interested in them.[128] NNG was obviously open to discussing fixed-rate conditions, since it agreed to them even though they were not included in any of the initial offers. MERC's witness Ms. Mead confirmed that MERC never attempted to negotiate additional conditions for a phased proposal.[129]

176. While it is true that the Phased Proposals did not initially include fixed-rate guarantees, neither did any of the other proposals. There does not appear to be any reason that MERC could not have requested fixed-rate conditions with a phased or incremental proposal.

d. MERC's argument that phased proposals did not provide cost certainty is not reasonable.

177. MERC also states that one reason it did not consider the Phased Proposals was that MERC would be responsible for actual construction costs for any deferred upgrades, while the up-front proposals provided cost certainty.[130]

178. While the first "phase" of NNG's phased proposals had a firm cost, NNG provided a cost estimate of the second "phase" and made clear that MERC would ultimately be responsible for the actual cost of construction. According to the Company, these proposals

[125] *Id.* at 13.
[126] *Id.* at 13–14.
[127] Tr. Evid. Hearing, Vol. 1, at 221–222 (Ryan).
[128] Ex. 306, Schedule 5, at 2 (Urban Direct HSTS Schedules).
[129] Tr. Evid. Hearing, Vol. 1, at 128:4–5 (Mead).
[130] Ex. 13, at 13 (Mead Rebuttal).

"[were] not considered as a viable alternative" because they did not provide long-term cost certainty.[131]

179. The OAG argued that MERC's statements are not reasonable. The lack of cost certainty is a factor that should have been weighed against the benefits that ratepayers would receive from a phased proposal.

180. In addition, MERC's concern with cost certainty appears to be inconsistent because the Company has made clear that it does not offer a fixed price guarantee to ratepayers for *its* costs. As Ms. Lyle pointed out, MERC's estimate of $44 million for distribution costs is not a "firm or fixed price and it should not be considered a guaranteed or not-to-exceed estimate."[132] MERC argues that it could not consider phased options from NNG because they did not provide "cost certainty," but MERC does not offer cost certainty to ratepayers for the distribution costs.

e. MERC's decision to reject proposals that delivered gas to existing TBSs is not consistent with MERC's distribution upgrades.

181. MERC states that it rejected some proposals because they did not deliver gas to the correct TBS or because the pressure would not be sufficient. In particular, Ms. Mead states that Phased Proposal 4.2 was rejected, in part, because "the new capacity would be provided at TBS 1B, which is not where MERC's substantial growth is."[133]

182. The OAG argued that there are several problems with this argument.

183. First, MERC has also clearly explained that the purpose of the distribution upgrades it plans to make will "interconnect" the northern and southern portions of the distribution system in Rochester.[134] It is clear that the distribution upgrades would permit MERC to receive the new capacity at any point along the distribution system and still be able to move the gas wherever it is needed.

184. Second, NNG made clear that the Phased Proposals were not exhaustive, and that they had the flexibility to work with MERC to modify any of the proposals to meet the Company's needs.

f. MERC's argument that an incremental or phased proposal would not satisfy short-term growth is factually incorrect.

185. MERC also states that it did not prefer phased projects because they would not provide incremental capacity quickly enough for MERC's preferences. In particular, the

[131] Ex. 19, at 16 (Sexton Rebuttal).
[132] Ex. 8, at 3 (Lyle Rebuttal).
[133] Ex. 16, at 17 (Mead Surrebuttal).
[134] Ex. 25, at 2 (Lyle Opening Statement).

Company states that it rejected at least one proposal, Phased Proposal 2.3, because the incremental addition of 10,000 Dth/day would not serve near-term growth requirements.[135] According to Ms. Mead's Direct Testimony, though, adding 10,000 Dth/day would completely solve the existing supply shortage, and ensure a positive reserve margin until the 2020/2021 heating season.[136] And that figure assumes that MERC's forecast is completely accurate—when modified to account for the forecasting problems addressed above, it is likely that an adequate reserve margin would persist further into the future.

g. MERC has not demonstrated that it was reasonable to focus on up-front proposals.

186. The OAG argued that a phased proposal could have provided clear benefits to ratepayers that would have addressed some of the primary concerns raised with MERC's proposal for the Rochester Project: the extremely high reserve margins, which represent capacity purchased by ratepayers for which there is no current demand, and the concerns with intergenerational inequity. By deferring some upgrades to a future time period when growth in demand has actually materialized, a phased proposal could have mitigated both of these problems, without significant additional expense and without losing the ability to negotiate.

187. MERC has not produced any explanation or documentation of the decision making process it used when it decided not to pursue a phased proposal, and none of the Company's arguments explain why the Company moved forward without a cost benefit analysis of some kind that recognized the unique benefits ratepayers could have received from phased proposals.

188. The record also shows that MERC did not give sufficient consideration to other alternatives, such as peak shaving facilities, which could have reduced the peak demand in the Rochester area and led to cost savings.

G. MERC DID NOT CONSIDER THE POSSIBILITY THAT CONSERVATION AND PEAK SHAVING FACILITIES COULD REDUCE THE MAGNITUDE OF NEED FOR THE ROCHESTER PROJECT.

189. In its Initial Petition, MERC described the alternative approaches it considered for the Rochester Project. MERC stated that it considered 1) transmission pipeline alternatives, 2) distribution modification alternatives, 3) conservation alternative, and 4) a no build alternative.[137]

190. The OAG identified several problems with MERC's analysis.

191. First, MERC should have provided significantly more information about the possibility that conservation could have reduced peak demand in the Rochester area and reduced the need for the Rochester Project.

[135] Ex. 19, at 13 (Sexton Rebuttal).
[136] Ex. 12, at 21, Table 1 (Mead Direct).
[137] Ex. 1, at 26–28.

192. Second, MERC's explanation as to why it did not reasonably consider peak shaving facilities that could have addressed a significant portion of the area's need.

193. Third, Ms. Lyle argues that a peak shaving facility would not resolve the distribution constraints, but ignored the possibility that peak shaving facilities could have also reduced the cost of interstate pipeline upgrades, as shown by OAG testimony.

194. In summary, it is possible that a peaking facility could have reduced the scale of the Rochester Project by serving some portion of demand on peak days. But MERC did not complete any kind of cost benefit analysis to determine whether it would be in the interests of ratepayers to do so. MERC has similarly ignored the possibility that increased conservation efforts could reduce growth in peak demand, and thus reduce the scale required for the Rochester Project. These failures indicate that MERC did not exercise the necessary care and thoroughness in its decision-making process before embarking on its plan for the Rochester Project.

H. THE ROCHESTER PROJECT SHOULD NOT BE JUSTIFIED BY INCREASED CONSUMPTION BY INTERRUPTIBLE AND TRANSPORT CUSTOMERS.

195. In his Direct Testimony, Department witness Mr. Heinen explained that estimates of peak demand measure the demand for firm customers:

> [W]hen a utility estimates peak demand for demand entitlement purposes, it focuses only on throughput for firm sales customers. It does not include interruptible load in this analysis because interruptible customers receive the benefit of lower non-gas margins knowing that they will be interrupted if load must be curtailed to maintain system integrity. Transportation load is also not included in estimates of peak day demand for demand entitlement purposes because these customers procure their entitlement level through a third-party vendor, not the gas utility.[138]

196. According to Mr. Heinen, a measurement of peak demand should include consumption by firm customers, and should *not* include consumption by interruptible or transportation customers.

197. Nearly every witness in this proceeding agrees. During the evidentiary hearing, MERC witness Ms. Lee agreed that the Design Day measurement of peak demand does not include any use by interruptible or transport customers.[139] Mr. Clabots confirmed that the Design Day forecast represents the demand of firm customers, and contains no usage for any interruptible or transport customers.[140] Ms. Mead agreed that the Design Day includes firm customers only.[141] MERC further confirmed this principle in OAG Information Request 156,

[138] Ex. 405, at 9 (Heinen Direct).
[139] Tr. Evid. Hearing, Vol. 1, at 24 (Lee).
[140] *Id.* at 79 (Clabots).
[141] *Id.* at 111:2–6 (Mead).

where Ms. Lyle and Ms. Lee stated that "interruptible and transport volumes do not factor into MERC's peak-day planning and therefore do not directly affect MERC's planning for its Rochester Project."[142]

198. The OAG argued that the problem is that both MERC and the Department have suggested that future consumption by interruptible and transportation customers provides justification for the Rochester Project. In particular, both MERC and the Department argue that growth in consumption by Rochester Public Utilities ("RPU") should be a factor in deciding whether the Rochester Project is prudent and reasonable.

199. The OAG argued, however, that any increased consumption from RPU will be *interruptible transportation* service, not firm service. In fact, RPU made this very clear when it stated, "Overall, RPU anticipates that its firm natural gas usage from Minnesota Energy Resources will remain relatively constant for the next decade. However, RPU's use of interruptible transportation service is likely to increase dramatically in the coming years." According to the vast majority of witnesses in this case, the fact that RPU will take interruptible transportation service means its consumption should not be considered when planning to serve peak demand. And, yet, both the Department and MERC have used RPU's future plans to justify the Rochester Project.

200. MERC did not mention RPU in its initial Petition or in its Direct Testimony. In fact, MERC did not raise the matter of RPU until its Rebuttal testimony. In Rebuttal, MERC witness Ms. Mead discussed the possibility that RPU would increase its consumption of natural gas in the future, but was careful to point out that "under existing tariffs . . . MERC is unable to dictate whether RPU takes service as a firm, interruptible, sales, or transport customer."[143] In her Surrebuttal testimony, though, Ms. Mead argued that RPU's plans to increase natural gas consumption is one reason to approve the Project. This is inconsistent with Ms. Mead's other testimony that interruptible and transport service should not be included in peak demand planning.

201. The OAG argued that Mr. Heinen makes the same mistake. Despite the statement in his Direct Testimony that peak demand does not include transportation service, in his Surrebuttal Testimony, Mr. Heinen suggested that the reserve margin analysis should be modified to account for RPU's future consumption. To complete his reserve margin analysis, Mr. Heinen assumed that the level of excess capacity would decrease by "10,000 to 20,000 Dkt/day" as a result of increased consumption by RPU.[144] During the evidentiary hearing Mr. Heinen confirmed that he used this figure because it was an estimate of daily use from RPU's planned West Side Energy Station.[145] But the record makes clear, and Mr. Heinen acknowledges, that the West Side Energy Station plans to take "interruptible transport service."[146] That means, according to Mr. Heinen's earlier testimony, that the additional

[142] Ex. 304, Schedule 32, at 3 (Urban Direct Schedules Public).
[143] Ex. 13, at 6 (Mead Rebuttal).
[144] Ex. 407, at 18 (Heinen Surrebuttal).
[145] Tr. Evid. Hearing, Vol 2, at 34 (Heinen).
[146] *Id.* (Heinen); Ex. 309, R-2 (Urban Rebuttal Schedules).

consumption from RPU should *not* be included in calculation of reserve margins because it will be transportation service. Mr. Heinen's reserve margin analysis directly conflicts with his own principles of planning for peak demand.

202. The utility's obligation is to ensure that firm customers receive safe and reliable service, not to plan to ensure service for interruptible and transportation customers. As Ms. Lee confirmed during the evidentiary hearing, MERC plans its natural gas system to provide service to firm customers, and "measure[s] the system based on the firm load."[147] MERC does not plan to ensure that interruptible and transport customers can receive service at all times,[148] and "interruptible and transport volumes do not factor into MERC's peak-day planning and therefore do not directly affect MERC's planning for its Rochester Project."[149] Based on these principles, it would be unreasonable to justify a significant infrastructure investment because of an expected increase in consumption by interruptible or transportation customers.

203. There are good policy reasons for these distinctions. As Mr. Heinen points out, the reason that interruptible consumption is not included in peak demand planning is that "interruptible customers receive the benefit of lower non-gas margins knowing that they will be interrupted if load must be curtailed to maintain system integrity."[150] Similarly, Mr. Heinen notes that, "Transportation load is also not included in estimates of peak day demand for demand entitlement purposes because these customers procure their entitlement level through a third-party vendor, not the gas utility.[151] Those principles should not be reversed in this case in order to justify overbuilding facilities that are not necessary to serve firm customers in the Rochester area.

204. In addition to those problems, the OAG also argued that it would be unreasonable to consider increased consumption from RPU as a justification MERC's proposal because MERC had no idea that RPU would be increasing natural gas use when the Company made its decision. MERC issued its RFP in December, 2014, received responses in January, 2015, negotiated the PA throughout 2015, and executed the PA in the fall of 2015.[152] MERC did not learn about any increased consumption for RPU until months later. In fact, MERC has gone out of its way to confirm that its forecast "did not model" any additional sales to RPU.[153] In other words, MERC decided to move forward with the Rochester Project as described in the PA *before* it was aware of any increased consumption from RPU. It is very clear that any increased consumption from RPU was not a significant factor supporting the Project when the Company was not even aware of it when the important decisions were made.

[147] Tr. Evid. Hearing, Vol. 1, at 26:1–10 (Lee).
[148] *Id.* at 26:11–13 (Lee).
[149] Ex. 304, Schedule 32, at 3 (Urban Direct Schedules Public).
[150] Ex. 405, at 9 (Heinen Direct).
[151] *Id.*
[152] Ex. 306, Schedule 5, 7 (Urban Direct Schedules HSTS); Tr. Evid. Hearing, Vol. 1, at 30:15–17 (Lee).
[153] Ex. 10, at 7 (Clabots Rebuttal).

I. THE BISON PIPELINE PROJECT PROVIDES AN EXAMPLE OF THE PROBLEMS THAT CAN RESULT FROM PIPELINE CONTRACTS.

205. The Rochester Project is not the first time MERC has asked the Commission to approve an interstate pipeline contract. In fact, the Company is currently recovering nearly $14 million per year for a pipeline that is barely being used—the Bison Pipeline Project.

206. In June, 2008, MERC filed a Petition requesting Commission approval of MERC's plan to contract for capacity on the Bison Pipeline Project.[154] The Bison Project was a proposed pipeline that would deliver natural gas from the Powder River Basin in Wyoming to Northern Border Pipeline Company in North Dakota, and then to MERC.[155] MERC contracted with Bison to deliver 50,000 Dth/day to the Northern Border pipeline at a rate of $0.55 per Dth, and then contracted with Northern Border to deliver 49,690 Dth/day to MERC's system at a rate of $0.23 per Dth.[156] The total cost over the ten year duration of the contracts was estimated to be approximately $140 million, or $14 million per year.[157] MERC asked the Commission for approval of its plan to contract for 50,000 Dth/day in capacity on the Bison Pipeline in order to diversify the utility's natural gas supply options.[158] Just as with the Rochester Project, MERC did not need approval from the Commission before contracting with Bison but sought the Commission's agreement to "ensure recovery of all reasonable and prudent costs associated with the project."[159] In three pages of comments and analysis, the Department, through Mr. Heinen,[160] recommended that the Commission approve MERC's request.[161]

207. In its Briefing Papers, Commission staff raised several concerns about the Bison Project investment. Staff noted that the Commission does not normally pre-approve cost recovery of contracts, and that gas utilities routinely enter into precedent agreements without Commission approval.[162] While Staff noted that there may be some merit to the concept of diversifying supply sources, the Briefing Papers concluded that the concerns about "cost and unreliability of Canadian supplies is probably exaggerated."[163] Staff also noted that the more typical approach for pipeline supply would be for the utility to contract for supply closer to the company's service area,[164] and that MERC's cost savings estimate was based on being able to

[154] Petition, *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval to Contract for Capacity on the Bison Pipeline Project*, Docket No. G-007, 011/M-08-698 (June 11, 2008).
[155] *Id.* at 3, 12
[156] *Id.* at 3.
[157] ($0.55 + $0.23) * 50,000 Dth/day * 365 days = $14.23 million per year.
[158] *Id.* at 3.
[159] *Id.*
[160] Despite Mr. Heinen's statements during the evidentiary hearing, Tr. Evid. Hearing, Vol. 2, at 68:21–24 (Heinen), Mr. Heinen signed the Department's recommendation to approve the Bison contract.
[161] Comments of the Minnesota Office of Energy Security, *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval to Contract for Capacity on the Bison Pipeline Project*, Docket No. G-007, 011/M-08-698 (Aug. 1, 2008).
[162] Briefing Papers, *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval to Contract for Capacity on the Bison Pipeline Project*, Docket No. G-007, 011/M-08-698, at 3 (Aug. 21, 2008).
[163] *Id.* at 5.
[164] *Id.*

exploit price differentials between pipelines when those prices appeared to be converging.[165] In light of these concerns, the Staff recommended that the Commission decline to take action on MERC's proposal. In support of its decision, Staff noted that there should be some incentive for the utility to ensure it is making good decisions "so that utilities have an incentive to enter into best-cost gas supply arrangements."[166] There does not appear to be any Commission Order disposing of MERC's request, but the Commission's minutes indicate that the Commissioners voted unanimously to take no action on the Petition.[167]

208. The Bison Pipeline has not been a good investment for MERC's ratepayers. In its Briefing Papers for the 2015–2016 Demand Entitlement filing, Commission Staff noted that "the Bison/NBPL contract option may not currently be the best or least cost gas option."[168] In fact, MERC explained in an e-mail to Mr. Heinen that MERC has utilized only half of the Bison capacity from 2011 to 2015.[169] As of December, 2015, MERC has *no* supply contract in place for the pipeline.[170] And, during that time, MERC has been unable to release any of the excess capacity because there were no takers in the capacity market.[171] According to Mr. Heinen, the average residential ratepayer is on the hook for approximately $38.09 per year for the Bison contract,[172] and it looks like at least half of that cost (and possibly more) serves no purpose. Despite these concerns, Staff noted in their Briefing Papers that MERC has no ability to get out of the costs for the Bison Pipeline because of the contract that was executed.[173]

209. The facts of the Bison case are different from the facts surrounding the Rochester Project. The Rochester Project primarily concerns gas supplies, while the Bison pipeline appears to be focused on gas sources. But there are enough similarities between the two pipeline projects to draw several conclusions.

210. First, like the Bison Pipeline, it does not appear that the Commission has a legal obligation to take action on the Rochester Project. While MERC has requested approval, the Company does not require that approval to move forward and there does not appear to be any requirement for the Commission to make a decision. But the facts of the Bison Pipeline show that taking no action on a pipeline contract petition does not provide sufficient protection for ratepayers. In fact, it can make it extremely difficult to challenge the reasonableness of expenses in the future. The decision not to act, when the Commission has the opportunity to do so, can be taken as tacit approval. And once a utility has executed a pipeline contract, it can be extremely

[165] *Id.* at 6.
[166] *Id.* at 8.
[167] Minutes, *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval to Contract for Capacity on the Bison Pipeline Project*, Docket No. G-007, 011/M-08-698 (Oct. 8, 2008).
[168] Briefing Papers, *In the Matter of a Petition by Minnesota Energy Resources Corporation for Approval of Changes in Contract Demand Entitlements for the 2015-2016 Heating Season Supply Plan effective November 1, 2015*, Docket No. G-011/M-15-722, at 12 (Apr. 12, 2016).
[169] Ex. 405, Schedule AJH-20 (Heinen Direct).
[170] *Id.*
[171] *Id.*
[172] Ex. 405, at 36 (Heinen Direct).
[173] Briefing Papers, *In the Matter of a Petition by Minnesota Energy Resources Corporation for Approval of Changes in Contract Demand Entitlements for the 2015-2016 Heating Season Supply Plan effective November 1, 2015*, Docket No. G-011/M-15-722, at 12 (Apr. 12, 2016).

difficult to insulate ratepayers from unreasonable costs that a utility has a contractual obligation to pay.

211. Second, the Bison Pipeline is an example of how important it is to review whether the assumptions used to justify a pipeline contract are reasonable. In its review of the Bison Pipeline, Staff noted that the costs and benefits were "largely based on MERC being able to exploit a difference in cost" for gas purchased from different area, but that concerns about the cost and unreliability of gas from Canada were "probably exaggerated."[174] Ultimately, it appears that a thorough investigation of these assumptions may have been able to protect ratepayers from unnecessary pipeline costs. In this case, the core assumptions used to justify MERC's proposal for the Rochester Project are the Company's 25-year growth forecast, the Company's decision that it must obtain exactly the amount of gas the forecast estimates will be demanded in the 2040s, and the Company's decision to move forward with a fully up-front project rather than a phased or incremental project. The evidence in this record demonstrates that these assumptions and decisions were not reasonable.

J. For All Of These Reasons, The Rochester Project Is Not Prudent, Reasonable, And Necessary To Provide Service To Customers In The Rochester Area.

212. In its Notice of and Order For Hearing, the Commission asked the Administrative Law Judge and the parties to investigate whether the Rochester Project investments are "prudent, reasonable, and necessary to provide service to MERC's Rochester service area."[175] The foregoing analysis demonstrates that the answer to this question is "no."

213. MERC based its decision on how large the Rochester Project should be solely on the results of its long-term demand forecast, a decision that places all of the risk inherent in long-term forecasts on ratepayers. The effect of that decision is compounded because there are significant errors in MERC's forecast. Namely, the two primary inputs into the forecast—the customer count model and the use-per customer model—were not reasonable. This resulted in a forecast that predicts continuous growth of 1.5 percent every year for the next 25 years—a figure that is more than three times the historical average for the region. MERC then tied the design of its RFP exclusively to the results of its forecast, and performed a flawed analysis on the RFP responses it received. In the course of that analysis, the Company effectively focused only on proposals that would provide, up-front, the full amount of natural gas that the forecast estimated would be needed in the 2040s, instead of giving full consideration to phased or incremental proposals that could have provided significant protections to ratepayers. And, on top of that, MERC categorically did not consider whether increased conservation or peak shaving facilities could have reduced the magnitude of need in the Rochester area. The result is a Rochester Project that will provide fifty percent more natural gas than is needed when the upgrades are complete, and will continue to provide double digit reserve margins for decades—a massively overbuilt project that MERC knows will be paid for by its captive ratepayers.

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[174] *Id.* at 5.
[175] Notice of and Order for Hearing, at 5 (Feb. 8, 2016).

214. The Commission should reject MERC's request for pre-approval of the Rochester Project. Instead, the Commission should direct MERC to pursue a different, more moderate plan for the Rochester area that improves the forecast methodology, does not expose ratepayers to the full extent of forecasting risk, and that takes advantage of the benefits of phased or incremental proposals to deal with the problems of unreasonably high reserve margins, intergenerational inequities, and unreasonable benefits for interruptible and transportation customers.

215. If the Commission does approve the Project, it should take steps to protect ratepayers from costs related to unreasonably high reserve margins and intergenerational inequities. If the Project moves forward, the Commission should find that a portion of the Rochester Project, related to the exceedingly high level of excess reserve margins, is not used and useful because it is not reasonably necessary to meet the demand of existing customers. The Commission should not allow recovery of this portion of the Project until the Company later demonstrates that growth has made it necessary to provide this amount of capacity to firm customers. The evidence demonstrates that the most appropriate resolution of this proceeding is for the Commission to find that the Rochester Project is not prudent and reasonable. As an alternative, however, the Commission could take these steps to protect ratepayers from the costs of MERC's unreasonable proposal.

VII. ELIGIBILITY FOR COST RECOVERY THROUGH AN NGEP RIDER.

216. The Rochester Project is not eligible for cost recovery under the Natural Gas Extension Project Costs ("NGEP") Rider Statute in Minnesota Statutes section 216B.1638.[176]

217. The NGEP Rider Statute was enacted following the harsh winter and propane shortage in 2013–14, and is intended to be utilized to promote the extension of natural gas service to propane-dependent areas of the state. But MERC interprets ambiguity in the NGEP statute to permit recovery of a project designed to serve customers in the Rochester area—an area that has been served by natural gas for over 80 years. Such a broad interpretation of the statute is not supported by legislative intent and would upend traditional revenue recovery for gas utilities in the state. Instead, the legislative history of the NGEP Rider Statute demonstrates that the Legislature intended the statute to be a new tool to encourage expansion of natural gas service in response to the propane shortage of 2014.

218. The question of rider eligibility is separate from the question of reasonableness and prudence.

A. THE NGEP RIDER STATUTE.

219. The NGEP Rider statute provides that a utility "may petition the commission outside of a general rate case for a rider that shall include all of the utility's customers, including

[176] In her Direct Testimony, Dr. Urban clearly stated that the question of NGEP Rider eligibility was a question of legal interpretation that would be addressed in the OAG's Initial Brief. Ex. 300, at 70 (Urban Amended and Corrected Direct). Dr. Urban stated that she raised the issue in her Direct Testimony "because the OAG wants to ensure that MERC is aware that the issue of rider eligibility may be raised in the future." *Id.*

transport customers, to recover the revenue deficiency from a natural gas extension project."[177] A natural gas extension project is "construction of new infrastructure or upgrades to existing natural gas facilities necessary to serve currently unserved or inadequately served areas."[178]

220. The NGEP Statute provides that the Commission "shall approve" the petition if two criteria are satisfied: "1) the project is deigned to extend natural gas service to an unserved or inadequately served area; and 2) the project costs are reasonable and prudently incurred."[179] Unserved or inadequately served area 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."[180] If approved, the utility is not permitted to recover more than 33 percent of the costs of the natural gas extension project through the rider."[181]

221. When a utility files a petition, the statute requires the petition to include specific information, including 1) a description of the project, including the number and location of new customers to be served; 2) the construction schedule; 3) the proposed budget; 4) the amount of any contributions in aid of construction ("CAIAC"); 5) a description of the efforts made by the utility to obtain CAIACs; 6) the amount of the revenue deficiency and the proposed allocation; 7) the proposed cost recovery mechanism; 8) the proposed termination date of the rider; and 9) a description of the benefits that will accrue to existing natural gas customers.[182]

222. The NGEP Statute explicitly provides that the Commission has the authority to "issue orders necessary to implement and administer" the Statute.[183]

B. THE NGEP STATUTE CONTAINS AMBIGUITY THAT REQUIRES INVESTIGATION OF LEGISLATIVE INTENT USING CANONS OF STATUTORY CONSTRUCTION.

223. This is the first proceeding before the Commission to deal with the NGEP Rider Statute and, as such, is the first time that the Commission must decide what the statute means. According to the Minnesota Supreme Court, "When interpreting the meaning of a statute, [the] primary goal is to 'interpret and construct laws so as to ascertain and effectuate the intention of the legislature.'"[184]

224. The OAG argued that some terms in the statute are unclear. In particular, one of the key provisions in the statute—the meaning of an "unserved or inadequately served area"—is ambiguous for two reasons. First, Minnesota law instructs that the Legislature intends technical terms, like "unserved" and "inadequately served" areas, to be read in concert with the special meaning they are given as terms of art. And, second, the NGEP Rider Statute is ambiguous

[177] Minn. Stat. § 216B.1638, subd. 2(a) (2015).
[178] *Id.* at subd. 1(e).
[179] *Id.* at subd. 3(b).
[180] *Id.* at subd. 1(i).
[181] *Id.* at subd. 3(c).
[182] *Id.* at subd. 2(b).
[183] *Id.* at subd. 4.
[184] *Lietz v. Northern States Power Co.*, 718 N.W.2d 865, 870 (Minn. 2006).

because accepting MERC's proposed interpretation would lead to an absurd and unreasonable result that the Legislature did not intend.

1. The NGEP Statute Is Ambiguous Because It Must Be Read In Concert With The Technical Definitions Of "Unserved" And "Inadequately Served" Areas.

225. According to the Minnesota Supreme Court, "[I]f a statute is susceptible to more than one reasonable interpretation, then the statute is ambiguous and we may consider the canons of statutory construction to ascertain its meaning."[185] The NGEP Rider Statute is susceptible of more than one reasonable interpretation because "unserved" and "inadequately served" areas are technical words that must be considered in the context of their special meanings in the industry.

226. MERC correctly notes that the NGEP Rider Statute includes a definition of "unserved or adequately served area." But that is not the end of the investigation, because according to Minnesota law, "when "technical words and phrases and such others as have acquired a special meaning . . . [they] are constructed according to such special meaning."[186] And "unserved or inadequately served area" is exactly that—a technical term of art that has a specific meaning within the realm of natural gas extension policy.

227. The technical meaning of "unserved or inadequately served area" envisions a far narrower conception of eligible projects that does not include already-served communities like Rochester.

228. "Unserved areas" have a specific meaning in the natural gas extension context. According to a publication from the National Regulatory Research Institute ("NRRI") titled *Line Extensions for Natural Gas: Regulatory Considerations*, "unserved areas" mean "areas remote from the nearest utility's gas system."[187] This definition is supported by MERC's New Area Surcharge tariff, which limits the New Area Surcharge rider to "geographical areas that have not previously been served by the Company."[188]

229. There is also an industry definition for "inadequately served" or "underserved" areas. According to NRRI, "inadequately served" or "underserved" areas are areas that "may have main [gas] lines nearby but [also have] many households and businesses that consume other forms of energy."[189]

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[185] *State v. Rick*, 835 N.W.2d 478, 482 (Minn. 2013).
[186] Minn. Stat. § 645.08 (2015); *see, e.g., Minn. v. RSJ, Inc.*, 552 N.W.2d 695, 701 (Minn. 1996) (noting that in reviewing legislative intent, a court will "construe technical words according to their technical meaning and other words according to their common and approve usage . . . .").
[187] Ken Costello, Nat'l Regulatory Research Inst., *Line Extensions for Natural Gas: Regulatory Considerations* 3 (Feb. 2013) [hereinafter "NRRI Report"].
[188] Minnesota Energy Resources Corporation Tariff, 2d Revised Tariff Sheet No. 9.14.
[189] NRRI Report, at 3.

230. Minnesota law requires that these technical terms be constructed according to their special meaning,[190] which is different from the way that MERC has suggested they be interpreted. Because they are susceptible of different interpretations, their meaning is ambiguous and must be ascertained using a more searching analysis.[191]

2. The NGEP Statute Is Ambiguous Because MERC's Proposed Interpretation Would Lead to An Absurd And Unreasonable Result.

231. The OAG argued that another reason that the meaning of "unserved or adequately served area" is ambiguous is that applying MERC's definition would lead to an absurd and unreasonable result. The Minnesota Supreme Court has held that courts, and commissions, are "obliged to reject a [statutory] construction that leads to absurd results or unreasonable results which utterly depart from the purpose of the statute."[192]

232. MERC's interpretation of the NGEP would lead to an absurd and unreasonable result. That means that according to Minnesota law, MERC's interpretation is not permissible.[193]

233. If the Rochester Project were deemed to be eligible for recovery under the NGEP rider statute, then the effect of the law would be so broad as to consume the vast majority of natural gas utilities' projects, rendering them eligible for non-rate case recovery via the NGEP rider. Such an outcome would present an unprecedented change to the utility regulatory process in Minnesota.

234. MERC is proposing NGEP rider recovery for a project "designed to improve the operation and efficiency of MERC's distribution system to ensure that all available firm gas on the system can be delivered across the system's entire footprint in southeastern Minnesota."[194] Put simply, the Rochester Project is a project designed to meet the needs of firm customers in one of, if not the most populous, longest-served areas in MERC's service territory. The Company stated: "As a system integrity and reliability project, the Rochester Project can be considered similar to other infrastructure projects included in rate base and recovered through base rates . . . . [many of the upgrades] are therefore comparable to the many other system repairs and upgrades MERC makes every year."[195]

235. The OAG argued that, under this logic, the Rochester Project would be no different than a routine distribution upgrade undertaken by CenterPoint in Minneapolis or Xcel in Saint Paul. The problem is that when applied to MERC's interpretation of the NGEP Rider

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[190] Minn. Stat. § 645.08 (2015); *see, e.g., Minn. v. RSJ, Inc.*, 552 N.W.2d 695, 701 (Minn. 1996) (noting that in reviewing legislative intent, a court will "construe technical words according to their technical meaning and other words according to their common and approve usage . . . .").
[191] *State v. Rick*, 835 N.W.2d 478, 482 (Minn. 2013).
[192] *Wegener v. Commissioner of Revenue*, 505 N.W.2d 612, 617 (Minn. 1993).
[193] Minn. Stat. § 645.17(1) (2015).
[194] Ex. 5, at 10 (Lee Direct).
[195] *Id.* at 23.

Statute, this would mean that almost *any* distribution system project *anywhere* would be eligible for rider recovery.

236. If MERC can recover one-third of the Rochester Project through the NGEP Rider, when MERC has been very clear in explaining that the Rochester Project will not actually extend service to any new areas or connect to any new customers, then there do not appear to be any infrastructure investments that would not be eligible for the NGEP Rider. Under that interpretation, natural gas utilities in Minnesota would begin recovering one-third of all of their investments through NGEP Riders. There is no indication in the NGEP Statue that the Legislature intended such a major regulatory shift.

237. To allow utilities to recover up to one-third of the cost for typical distribution system projects, especially larger projects such as the Rochester Project, could allow a utility to significantly increase revenue recovery without subjecting itself to review under a rate case.[196]

238. The OAG cautioned that such an outcome would upend the traditional rate recovery process for natural gas utilities in Minnesota and could not possibly be what the Legislature intended when it enacted this statute in response to the severely-cold, propane-stressed winter of 2013–14.

239. The NGEP rider statute was enacted with a very specific purpose: to promote expansion of natural gas to areas of the state where existing policies still left some communities short.

240. The NGEP Rider Statute was *not* meant to upend decades of policy by allowing every natural gas utility to perform an end-run around normal regulatory procedures in order to recover one-third of most of its investments through a rider. Such a result would be absurd, and is an indication that there is ambiguity in the statute. As the Minnesota Supreme Court has pointed out, decision-makers are "obliged to reject a construction that leads to absurd results or unreasonable results which utterly depart from the purpose of the statute."[197] When the literal language meaning put forward by one party would lead to this result, "it is necessary to look to the purpose for which the statute was enacted."[198]

3. Because The NGEP Statute is Ambiguous, The Commission Must Determine The Legislature's Intent.

241. The OAG argued that the language in the NGEP Rider is ambiguous for two reasons. First, the technical terms "unserved" and "inadequately served" area must be considered in the context of their special meanings according to Minnesota law. And, second, interpreting the NGEP Rider Statute as MERC proposes would produce an absurd and unreasonable result that the Legislature did not intend.

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[196] Under the interpretation of the NGEP rider statute advanced by MERC, and with the availability of the Gas Utility Infrastructure Costs ("GUIC") rider in Minnesota Statutes section 216B.1635, a utility could conceivably recover all "safety-related" infrastructure costs via a GUIC rider and one-third of any non-safety-related, distribution system costs via the NGEP rider. It is unclear, at that point, exactly which costs would *not* be recoverable through one of the recently enacted rider mechanisms.

[197] *Wegener v. Commissioner of Revenue*, 505 N.W.2d 612, 617 (Minn. 1993).

[198] *Id.*

242. As a result of this ambiguity, the Commission must "'consider the factors set forth' by the Legislature for interpreting a statute."[199]

C. THE LEGISLATURE INTENDED THE NGEP STATUTE TO LIMIT ELIGIBILITY TO SPECIFIC PROJECTS DESIGNED TO EXTEND NATURAL GAS SERVICE.

243. As discussed above, the Minnesota Supreme Court has declared that the "the primary goal is to 'interpret and construct laws so as to ascertain and effectuate the intention of the legislature."[200]

244. The Legislature has provided a series of factors that must be used in doing so. Minnesota Statutes section 645.16 provides eight factors that are used to investigate legislative intent, including: 1) the occasion and necessity for the law; 2) the circumstances under which it was enacted; 3) the mischief to be remedied; 4) the object to be attained; 5) the former law, if any, including other laws upon the same or similar subjects; 6) the consequences of a particular interpretation; 7) the contemporaneous legislative history; and 8) legislative and administrative interpretations of the statute.

245. The OAG argued that a fair review of each of these factors demonstrates that they all weigh against MERC's proposed interpretation of the NGEP Rider Statute. Instead, the mandatory factors demonstrate that the Legislature intended the NGEP Rider Statute to be used to promote the expansion of natural gas service in Minnesota to communities where it is otherwise uneconomical to extend service. The historical context and legislative history provides support and an explanation for the occasion and necessity of the law, the circumstances under which it was enacted, and the mischief to be remedied, in accordance to the statutory guidance on legislative intent.[201]

1. The NGEP Rider Statute Was Intended To Continue Minnesota's Policy Goal To Encourage Expansion Of Natural Gas Service.

246. It has been a long-held state policy goal to encourage expansion of natural gas service across the state to areas that are otherwise reliant upon other fuels such as propane for heating.

247. In 1992, the Commission acknowledged the "significant benefits" to both customers and communities conferred by the "expansion of the availability of natural gas in areas of Minnesota not currently served."[202] Over the years, policymakers have developed policies that promote expansion of natural gas while also balancing the interests of existing customers.

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[199] *State v. Peck*, 773 N.W.2d 768, 772 (Minn. 2009).
[200] *Lietz v. Northern States Power Co.*, 718 N.W.2d 865, 860 (Minn. 2006) (*quoting Olmanson v. LeSeur County*, 693 N.W.2d 876, 879 (Minn. 2005)).
[201] Minn. Stat. § 645.16 (2015).
[202] Order Rejecting Proposed Tariffs and Requiring Report, *In the Matter of a Request by Peoples Natural Gas for Approval of a New Town Least Cost Energy Rate et al.*, Docket Nos. G-011/M-91-296, G-007/M-91-460, G-008/M-91-575 2 (Mar. 10, 1992).

248. Generally, a utility will extend gas service to a new community if it is economical to do so.[203] That means that the incremental cost of adding that community must equal or surpass the benefit of additional revenue provided by the new customers. In theory, communities that are economical to serve will have already been served by a utility.[204] For example, it was presumably economical to serve the Rochester area in 1932, when a predecessor of MERC first began buildout of the system.[205] In contrast, a potential new community where the incremental cost of extending service outweighs the expected additional revenue, would be uneconomical to serve.[206] Extending service to this uneconomical community would be inequitable to the utility's current ratepayers, who would be asked to subsidize the uneconomic costs of the new area customers. Figure 1 illustrates this concept.

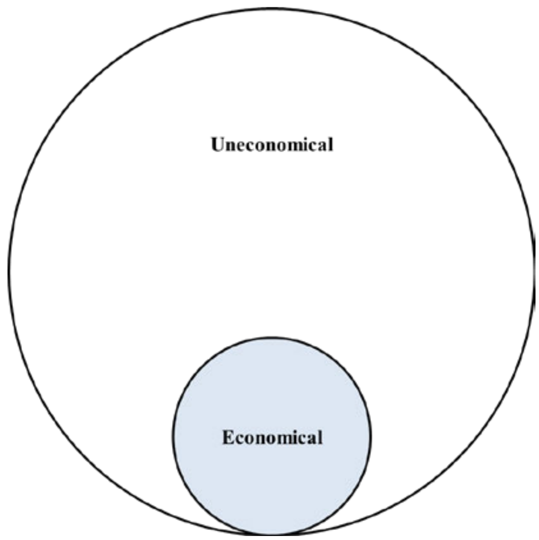

Figure 1: A visual depiction of a pool of potential natural gas customers, some of whom are economical to serve while the rest are not economical to serve.

249. Under this scenario, potential new area customers may be reluctant to pay the hefty upfront costs of expansion and the utility may be reluctant to extend service without additional revenue certainty. The expansion of natural gas service to these typically remote communities thus "appears unlikely to occur unless the LDCs are allowed to recover their excess

[203] *See* Minnesota Energy Resources Corporation Tariff, at 2nd Revised Tariff Sheet Nos. 9.05–06 (stating that the "Company will apply the general principal [sic] that the rendering of service to the applicant shall not result in undue burden on the other customer" and that the Company may refuse to extend service "if in the Company's judgment it is not economically feasible").

[204] *See* Order Rejecting Proposed Tariffs and Requiring Report, *In the Matter of a Request by Peoples Natural Gas for Approval of a New Town Least Cost Energy Rate et al.*, Docket Nos. G-011/M-91-296, G-007/M-91-460, G-008/M-91-575 2 (Mar. 10, 1992) ("At this time, however, it appears that most of the communities that can be economically served by existing LDC networks under current gas tariffs are being served.").

[205] *Our History*, http://www.minnesotaenergyresources.com/company/history.aspx (last visited Sept. 30, 2016).

[206] The new area community could self-fund the uneconomical costs associated with extension of service, but these high one-time costs can deter potential customers from extending service, even when long-term benefits are high and long-term costs are low. *See* NRRI Report, at 15–16.

extension costs directly from customers."[207] Minnesota was an early adopter of a special policy, the New Area Surcharge ("NAS"), designed to further promote expansion of natural gas service in order expand the radius of economically-viable communities in the state.[208]

250. The first NAS tariffs were implemented in Minnesota in the early-1990s. The purpose of an NAS is to "permit a natural gas company to extend service into a new area it would be uneconomic to serve at tariffed rates, by permitting the company to collect a surcharge [upon new area customers] in addition to the tariffed rate."[209] The NAS is "designed to recover the portion of the cost of service attributable to uneconomic service extensions" as determined by a feasibility model.[210] Broadly, the feasibility model takes into consideration the project's capital costs minus the revenues (based on current rates) collected from the additional customers.[211] The difference is the contribution in aid of construction that will be collected via the NAS rider over a specified period of time. By allowing new area customers to pay the uneconomic costs of the extension over time, the NAS incrementally expands the number of communities that can be served by natural gas, as Figure 2 below illustrates.

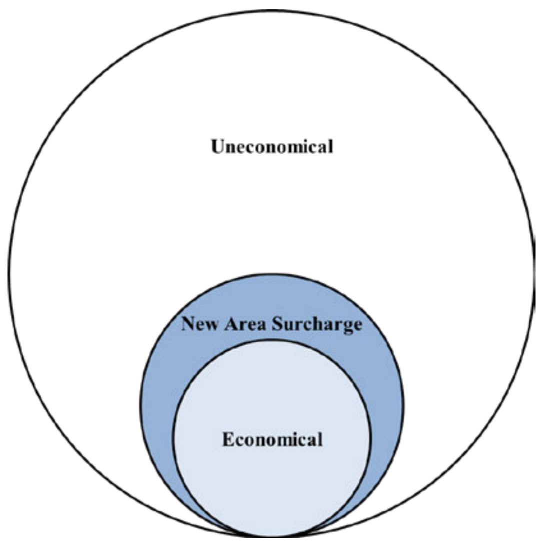

Figure 2 A visual depiction of a pool of potential natural gas customers illustrating the impact that the New Area Surcharge has on the expansion of the pool of potential customers.

[207] Order Rejecting Proposed Tariffs and Requiring Report, *In the Matter of a Request by Peoples Natural Gas for Approval of a New Town Least Cost Energy Rate et al.*, Docket Nos. G-011/M-91-296, G-007/M-91-460, G-008/M-91-575 2 (Mar. 10, 1992)
[208] NRRI Report, n. 7.
[209] Order Approving New Area Surcharge with Modifications and Requiring Revised Tariff Sheet, *In the Matter of Minnesota Energy Resources Corporation's (MERC) Petition for Approval of a New Area Surcharge Rider* 1 (Jul. 26, 2012).
[210] *Id.* at 2.
[211] *See, e.g.* Minnesota Energy Resources Company Tariff, at 9.14–16 (describing the "standard model" used in the calculation of an NAS surcharge).

This policy change did not extend natural gas service to *all* communities in the state, however, as some areas of the state remained uneconomical to serve even after proliferation of NAS tariffs.

251. These communities, which remained out of reach even with an NAS surcharge, became the focus of legislative attention following the winter of 2013–14. The winter heating season of 2013–14 was unusually cold, resulting in increased demand for natural gas and other heating fuels. In addition, a propane shortage caused by the high demand and regional supply challenges stressed propane-dependent communities.[212] The propane shortage that winter was so acute that Governor Dayton declared a state of emergency across the state on January 27, 2014.[213] As a result, policymakers began to explore alternatives that could allow the propane-dependent communities to switch to a cheaper alternative fuel like natural gas. Figure 3 shows the intended goal, which again increased the radius of communities eligible for the extension of natural gas service.

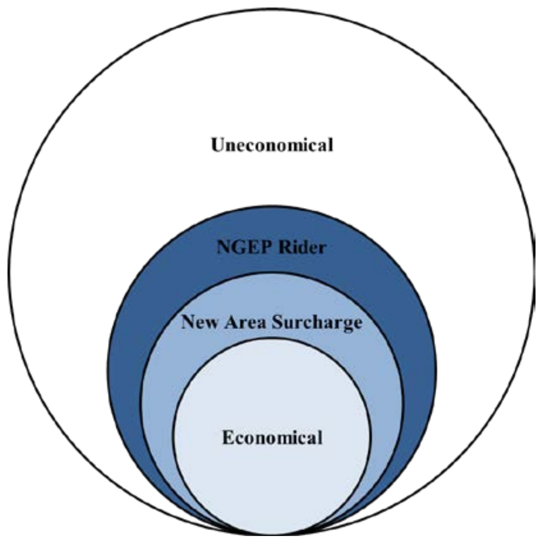

Figure 3 A visual depiction of a pool of potential natural gas customers illustrating the impact that the New Area Surcharge and the NGEP rider statute have on the expansion of the pool of potential customers.

All of the evidence, discussed below, indicates that the Legislature intended for the NGEP Rider Statute to supplement existing line extension policy by allowing existing customers to share in 33 percent of the costs of extending service to new customers.

[212] *See* Legislative Energy Commission, *Propane Conversion Strategies* 5–6 (Jan. 15, 2015) *available at* https://www.leg.state mn.us/docs/2015/mandated/150040.pdf (noting that unexpectedly high demand and delivery constraints contributed to a propane shortage in Minnesota and more than 30 other states).
[213] State of Minn. Executive Dep't, *Emergency Executive Order 14-02: Declaring a State of Peacetime Emergency in the State of Minnesota* (Jan. 27, 2014).

2. Legislative History Of The NGEP Rider Statute.

252. Following the winter of 2013–14 and prior to enactment of the NGEP statute, the Legislative Energy Commission ("LEC"), which evaluates state energy policy for the Legislature, issued a report on the propane shortage and identified potential alternatives to relieve stress on propane-dependent communities.

253. One alternative suggested by the LEC report was to develop policies to promote the extension of natural gas service to communities that were still uneconomical to serve, even with an NAS rider.[214] The report noted that the maximum amount of NAS surcharge typically accepted by potential new area customers was about $25 per month.[215] Given that NAS policy limits the duration of an NAS rider,[216] the $25 a month charge necessarily limits the amount of revenue that can be collected from new area customers, which can leave some potential new area communities with a revenue deficiency and, thus, no natural gas service. In order to bridge this revenue deficiency, the LEC report suggested that the Legislature "could consider giving state-regulated utilities greater flexibility in how these costs are covered" by building an "expansion fund" via a rider "to subsidize the costs of expansion projects."[217]

254. The NGEP rider bill was intended to give utilities this flexibility when it was introduced in March 2015.[218] The Senate Committee on Environment and Energy held a hearing on the NGEP bill shortly thereafter. At the hearing, a co-author of the NGEP bill explained the rationale behind the bill:

> [T]he current process analyzes if there is a revenue deficiency or not and then allows the option of having a New Area Surcharge added on to help cover the deficiency. If that is not enough to cover the deficiency, the project does not go forward. So what we're proposing . . . is to, in order to cover that deficiency, to allow the current, existing member base to pay part of the cost of the expansion . . . up to 33 percent of the project cost, to help cover the deficiency in order to move natural gas usage forward in Minnesota.[219]

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[214] Legislative Energy Commission, *supra* note 212, at 13.
[215] *Id.* at 15.
[216] Minnesota Energy Resources Corporation Tariff, at 2nd Revised Tariff Sheet No. 9.15 (limiting the duration of an NAS rider to 30 years). Interestingly, the Department recommended that the Company lengthen the duration of the NAS rider to 30 years from 15 in its 2013 rate case in order to "make it easier for new areas to obtain natural gas service rather than depending on propane service that may not be reliable" in response to the propane shortage of 2013–14. Direct Testimony of Michael Zajicek, *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-13-617 12 (Mar. 4, 2014).
[217] Legislative Energy Commission, *supra* note 212, at 15.
[218] S.F. 1263, 89th Leg. (Minn. 2015) and H.F. 1522, 89th Leg. (Minn. 2015).
[219] Audio: March 17, 2015 hearing of the Senate Committee on Environment and Energy (Statement of Sen. Skoe) *available at* https://www.leg.state mn.us/senatemedia/saudio/2015/cmte_envenergy_031715a.MP3 (remarks begin at approx. 5:00 minute mark).

255. A representative of MERC also testified at the hearing. He noted that MERC had received calls from 25 towns and townships since the previous winter, seeking help to extend gas service.[220] The representative gave two examples of towns—one small and one large, both situated where the additional NAS revenue would *not* fully cover an expansion—and noted that, to cover the revenue shortfall, the average annual increase for a typical MERC customer over the life of the extension would be between $0.02 and $0.37.[221] No mention was made of utilizing the NGEP rider to fund a massive distribution upgrade in communities that already had gas service.

256. The NGEP statue was enacted in May 2015.[222] The new statute incrementally expands the type of communities eligible to receive natural gas extensions and it followed a particularly harsh winter that brought a statewide propane shortage into full relief. Moreover, it fits into decades of policy development in Minnesota to promote extension of natural gas service while balancing equity concerns of existing ratepayers. The language and the structure of the statute also support this intention by the Legislature.

3. The Language And Structure Of The NGEP Statute Support The Narrower Interpretation Of Eligibility Argued By The OAG.

257. The OAG argued that, in addition to the particular policy and legislative history of the NGEP rider statute, the language and structure show that it is tailored to address the Legislature's specific concerns with encouraging additional expansion of natural gas service following the propane crisis.

258. When considered in the correct context, the different parts of the NGEP Rider Statute demonstrate that they are intended to supplement and extend the existing policies for extending natural gas service. In particular, the definition of the applicable areas, the 33 percent cap on recovery, and the inclusion of construction in aid of construction ("CIAC") and the revenue deficiency all have a specific meaning that is unique to the discussion of line extensions for natural gas service. Under Minnesota law, it must be presumed that "the legislature intends the entire statute to be effective and certain."[223] To give full effect to each of these concepts, the NGEP Rider Statute must be read in understanding with existing line extension policy.

259. First, the "unserved or inadequately served" terms in the NGEP Rider Statute must be understood in the context of existing policies for extending natural gas service. According to the NRRI, unserved areas "refers to areas remote from the nearest utility's gas system."[224] This understanding is supported by MERC's NAS tariff, which limits the NAS rider to "geographical areas that have not previously been served by the Company."[225] MERC

[220] *Id.* (Statement of Mr. Jeff Larson) (remarks begin at approx. 20:00 minute mark).
[221] *Id.*
[222] 2015 Minn. Sess. Law Serv. 1st Sp. Sess. Ch. 1 Sec. 20 (H.F. 3) (West).
[223] Minn. Stat. § 645.17(2) (2015).
[224] NRRI Report, *supra* note 206, at 3.
[225] Minnesota Energy Resources Corporation Tariff, at 2nd Revised Tariff Sheet No. 9.14.

explicitly distinguishes the Rochester Project from typical NAS-eligible projects, likening the project to a system integrity project rather than a gas extension project.[226]

260. In addition, as discussed above, the terms "inadequately served" or "underserved" areas have special meaning in the context of natural gas extensions. According to NRRI, "inadequately served or "unserved areas" "may have main [gas] lines nearby but many households and businesses that consume other forms of energy."[227] There is no record evidence that the Rochester area meets fits this definition either. An "inadequately served area" cannot mean an already-served area that needs additional capacity, as MERC argues with respect to Rochester.[228] In addition to resulting in an absurd broadening of eligible projects (discussed above), interpreting "unserved or inadequately served area" as broadly as the Company proposes has the effect of cancelling out other vital elements of the statute.

261. The 33 percent cap also indicates that the NGEP Rider Statute was intended to supplement the NAS system, rather than allow recovery of distribution costs to existing customers. The 33 percent cap in the NGEP statute has a specific purpose within the natural gas extension policy realm. It is intended to "help cover the deficiency," as one legislator commented, that the NAS could not fully fund.[229] Neither the initial petition nor subsequent testimony submitted by the Company comments in detail on this element of the statute, other than a general restatement that a cap exists.[230]

262. Only with the historical context about the NAS and extension policy provided above does the 33 percent cap become meaningful. Prior to enactment of the NGEP rider statute, it was the policy of the Commission to require new area customers to pay the *entire* share of the uneconomic extension costs via the NAS rider. The NGEP Rider Statute is a new tool that allows new area customers to pay only 67 percent of the costs of uneconomic extensions, while the other 33 percent are paid for by existing customers. The 33 percent cap is thus a specific tool designed and intended balance the contribution of *all* of a utility's ratepayers to fund the uneconomical portion of natural gas extension project costs with the interest of the state to extend natural gas service to unserved or underserved communities.

263. Similarly, contribution in aid to construction ("CIAC") also plays a very specific role in the statute.[231] CIAC reflects the need of the utility to charge certain customers, such as

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[226] "Q. Is the Rochester Project more akin to a new customer extension project . . . than to a system integrity project? A. No. Phase II is not being undertaken to connect specific new customers to our distribution system nor to extend the distribution system to new customers in an area that MERC is not already serving." Ex. 5, at 24 (Lee Direct).

[227] NRRI Report, at 3.

[228] "The Rochester Project is being constructed in an area that MERC already serves but is inadequately served as described in the NGEP statute." Ex. 5, at 24–25 (Lee Direct).

[229] Audio: March 17, 2015 hearing of the Senate Committee on Environment and Energy (Statement of Sen. Skoe) *available at* https://www.leg.state mn.us/senatemedia/saudio/2015/cmte_envenergy_031715a.MP3 (remarks begin at approx. 5:00 minute mark).

[230] *See, e.g.,* MERC's Initial Petition, at 29 (noting that "only 33% of the revenue deficiency . . . may be recovered through the rider . . . .").

[231] The statute defines CIAC as "a monetary contribution, paid by a developer or a local unit of government to a utility providing natural gas service to a community receiving that service as a result of a natural gas extension

(Footnote Continued on Next Page.)

new customers on the system, a special fee when those customers demand reside in an area remote from the utility's infrastructure.[232] Under the NGEP statute, a petition for NGEP rider recovery must contain a description of any CIAC as well as "a description of efforts made by the public utility to offset the revenue deficiency through contributions in aid to construction."[233] In other words, the NGEP Rider Statute is written with the assumption that some CIAC will be collected—that is because the statute is intended to supplement existing natural gas extension policies, and those policies would *always* require a CIAC to be collected.[234] Here, MERC acknowledges that, "[w]hile new customers pay a CIAC to connect [via the NAS], customers will *not* be connecting directly to Phase II of the Rochester Project . . . ."[235] As a result, there will be no CIACs to offset the Rochester upgrades. While it is not an explicit requirement that petitioners must have some amount of CIAC, it is clearly envisioned by the Legislature that CIAC from potential new customers would be an important component of an NGEP rider petition and it further requires utilities to describe "efforts made" to offset the deficiency via CIAC.[236]

264. Finally, the revenue deficiency, as defined in the statute, describes the "deficiency in funds" that occurs when the "projected revenues from customers receiving natural gas service as the result of a natural gas extension project, plus any [CIAC], fall short of the total revenue requirement of the natural gas extension project."[237] The total revenue requirement is defined as the "total cost of extending and maintaining natural gas service to a currently unserved or inadequately served area."[238] This formula is functionally similar to the process used for other line extension policies, except it requires the new area customers to pay only 67 percent of the costs, while existing customers would pay 33 percent of the costs. As the legislative history suggests, the entire purpose of the NGEP rider statute is to allow utilities to close the gap between the revenue collected from new customers with the NAS accounted and the project costs. Further, the 33 percent cap reflects the understanding of the Legislature that this deficiency would not be likely to exceed 33 percent of project costs. In other words, where the utility and the new area community fell short of economically extending service, the NGEP rider would allow the utility and all of its current ratepayers to bridge the revenue gap up to 33 percent.

265. MERC, however, indicates a "revenue deficiency" of more than 70 percent by 2019[239] and simply calculates the rider-eligible revenue deficiency as 33 percent of its total revenue requirement. The significant difference between MERC's revenue deficiency and the

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(Footnote Continued From Previous Page.)

project, that reduces or offsets the difference between the total revenue requirement of the project and the revenue generated from the customers served by the project." Minn. Stat. § 216B.1638 subd. 1(b) (2015).

[232] NRRI Report, at n. 76.

[233] Minn. Stat. § 216B.1638 subd. 2(b)(4)–(5) (2015).

[234] *See* Mar. 12, 1992 Office Memorandum from Kate O'Connell & Bob Harding to Commissioners, *Issues for new-area rates*, in Docket Nos. G011/M-91-296, G007/M-91-460, G008/M-91-575 2 (noting the recommendation from staff that "the [New Area] surcharges should be considered as CIACs rather than rates").

[235] Ex. 1, at 29–30 (Petition) (emphasis added).

[236] Minn. Stat. § 216B.1638 subd.2(b)(5) (2015).

[237] *Id.* at subd. 1(f).

[238] *Id.* at subd. 1(g).

[239] Ex. 1, Table 9 (Petition) (2019 revenue deficiency $2,359,549 / 2019 revenue requirement $3,211,424 = 73.5%).

one envisioned in the statue further indicates that the Legislature did not intend the NGEP Rider Statute to apply to investments such as the Rochester Project.

266. There is a presumption that the Legislature intends for the entire statute to be effective and certain.[240] The OAG argued that MERC attempts to ignore or write-off important elements of the statute in order to shoehorn the Rochester Project into the eligibility criteria listed in the statute. Instead, the specific terms in the NGEP rider statute, and the way in which those terms relate to existing line extension policies, demonstrate that the Legislature intended the NGEP Rider Statute to be a new tool to encourage extension of natural gas service to new customers in response to the propane shortages in 2014—and nothing more. In fact, when considered in the proper context, it is clear that the Legislature engaged in a complicated balancing act and determined that the state policy in favor of extending natural gas use, and the problems caused by shortage of other fuels, would justify requiring existing customers to fund one-third of the costs of extending new service in some circumstances. That careful consideration should not be twisted into a different policy that allows a utility to recover 33 percent of the costs of continuing to provide service to existing customers through a rider.

D. THE LEGISLATURE DID NOT INTEND THE NGEP RIDER STATUTE TO APPLY TO INVESTMENTS LIKE THE ROCHESTER PROJECT.

267. As discussed above, the Legislature has created eight criteria that should be applied to determine the intent of a statute.[241] Each of those criteria is satisfied in this case.

268. The first four criteria deal with the occasion and necessity for the law, the circumstances under which it was enacted, the mischief to be remedied, and the object to be attained.[242] These criteria all demonstrate that the purpose of the NGEP Rider Statute was to support, and supplement, existing natural gas line extension policies. A review of the legislative history of the NGEP Rider Statute demonstrates that it was passed in response to the historic problems caused by the propane shortage in 2013–14. In part because of these problems, the Legislature wanted to create a new policy that would encourage natural gas expansion, even in some currently uneconomical circumstances, by allowing existing ratepayers to share in the costs of line extensions for the first time.

269. The "former law," to be considered according to the fifth criteria, is existing line extension policy.[243] In that light, the NGEP Rider Statute is a rational step beyond existing policies. Before the NGEP Rider Statute, customers that did not have access to natural gas could get access if they were willing to pay a CIAC to cover the additional costs of extending service. The NGEP Rider Statute further encouraged that type of development by reducing the financial burden of CIACs by 33 percent, and spreading it to existing ratepayers.

[240] Minn. Stat. § 645.17(2) (2015).
[241] Minn. Stat. § 645.16 (2015)
[242] *Id.*
[243] *See id.*

270. The sixth criteria instructs that it is important to consider the consequences of different interpretations of a law.[244] As discussed above, MERC's interpretation of the NGEP Rider Statute would significantly change the regulatory structure in Minnesota by allowing natural gas utilities to recover up to one-third of *most* of their investments through a new rider. If the Rochester Project is eligible for NGEP Rider recovery, then there appear to be few rational reasons that MERC or other utilities could not request that most of their projects go through the NGEP Rider in the future. There is no indication that the Legislature intended such a dramatic shift in the regulatory structure from this statute. Instead, there is every indication that the statute was intended to address a single, specific problem related to the economics of line extension policies in the state.

271. The seventh criteria refers to the contemporaneous legislative history, which has been discussed throughout this section.[245] In addition to providing insight on the Legislature's intentions, that legislative history shows that when MERC testified during the hearings on the NGEP Rider Statute, the Company discussed line extension policies, and did not discuss infrastructure investments to existing customers.

272. The eighth criteria does not apply in this instance, because this is the first-ever interpretation of this statute.[246] As such, there are no decisions by legal or administrative bodies from which to draw inspiration. Instead, the Commission must base its decision on the intent of the Legislature.

273. MERC's interpretation is that the Legislature intended the "Natural Gas Extension Project Rider" statute to recover the costs of projects that are undertaken to ensure continued safety and reliability to existing customers. The obvious conclusion following this interpretation would be that utilities can request recovery of up to 33 percent of normal infrastructure investments through the NGEP Rider. And, as discussed above, there is no requirement to obtain pre-approval before moving forward with such investments or requesting recovery. The Legislature did not intend such a significant change in regulatory policy. Instead, all of the available evidence demonstrates that the Legislature intended the NGEP Rider to supplement and expand existing line extension policies. The NGEP Rider Statute should be used for that purpose, but the Rochester Project is not eligible for recovery under this rider.

VIII. COST ALLOCATIONS FOR THE ROCHESTER PROJECT.

274. MERC has proposed to handle the cost allocation of the Rochester Project in two different ways. For those costs incurred by MERC, for Phase II distribution upgrades, MERC proposes to recover the costs from all of its firm customers, including customers who do not live in the Rochester area or the NNG PGA. For those costs related to expanding NNG's interstate pipeline capacity, MERC proposes to recover the costs through the commodity portion of the on a per-therm basis from all customers subject to the NNG-PGA.

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[244] *Id.*
[245] *Id.*
[246] *Id.*

275. If the Commission agrees that MERC has not demonstrated that the Rochester Project is prudent, reasonable, and necessary to provide service to customers then it need not make a decision on the cost allocations. If the Rochester Project is approved, though, the evidence in the record supports the Company's proposal for allocating the costs of the Phase II distribution upgrades. For the costs of the NNG pipeline capacity, however, the OAG argued that the Commission should require MERC to ensure that the NNG costs are borne by all customers, including transportation customers, in a manner commensurate with the benefit received.

A. The Evidence In The Record Supports MERC's Cost Allocation Proposal For Phase II Costs.

276. MERC proposes to recover its Phase II capital costs from all of its customers via base rates and the NGEP rider.[247] Thirty-three percent of the Phase II costs would be recovered via the NGEP rider under the Company's proposal, with the remaining costs recovered through base rates when rate cases are filed.[248] The Department recommends, instead, that customers outside the Rochester area should pay for only 50 percent of the costs, with the remaining 50 percent recovered from customers inside the Rochester area.[249]

277. MERC disagreed with the Department's recommendation for several reasons. First, MERC states that "spreading costs equally across all customers is consistent with Commission precedent that spreads system upgrade costs across the entire rate base and with the policy underlying the NGEP Rider statute."[250] Second, MERC states that "customers in other locations also benefit from the Project."[251] Third, MERC states that "a disproportionate split would effectively create separate rate zones within the MERC system."[252] Fourth, MERC states that the 50/50 split would be a "potentially excessive cost burden on [Rochester] customers."[253]

278. The record supports several of MERC's arguments. It is true that the general policy in Minnesota is to spread system upgrade costs amongst all customers. In instances where costs are incurred to add new customers to the system, there are specific policies in place that require new customers to contribute if the connection costs are uneconomical.[254] But the Phase II distribution upgrades are "not being undertaken to connect specific new customers" nor are they intended to "extend the distribution system to new customers in an area that MERC is not already serving."[255] Rather, Phase II is a "system integrity and reliability project" that is "similar to other infrastructure projects included in rate base and recovered through base rates."[256] The

[247] Ex. 5, at 21 (Lee Direct).
[248] *Id.* at 25.
[249] *See* Ex. 400, at 3 (Peirce Direct) (noting that Rochester area customers receive the most direct benefits of the distribution upgrades).
[250] Ex. 6, at 10.
[251] *Id.*
[252] *Id.*
[253] *Id.* at 11.
[254] Section II contains a more thorough discussion of line extension policy.
[255] Ex. 5, at 24 (Lee Direct).
[256] *Id.* at 23.

Commission's general policy is to spread the costs of system integrity and reliability projects among all customers.

279. One reason for that policy is that there are difficult questions of where to draw the line when assigning system integrity and reliability projects to specific customers. If 50 percent of the Rochester Project costs are assigned to Rochester customers, it is difficult to see why that policy should not be applied to all distribution projects that are intended to serve specific areas, which could be the vast majority. The Rochester Project is unique, but it is unique in the way the Company is seeking approval of the project, not because of the project itself. It is unclear why a system integrity and reliability project in Rochester should be treated differently than a similar project in any other community. Taken to its logical conclusion, directly assigning the costs of distribution projects would lead to a multitude of rate areas across MERC's system. That has not been the Commission's policy, generally. In fact, during the evidentiary hearing Ms. Peirce acknowledged that she was not aware of any instance where the Commission has required customers in a specific area to pay more than all other customers for infrastructure-related costs like the Rochester Project.[257]

280. In addition, it appears that the language of the NGEP Rider Statute supports spreading costs to all customers. The NGEP rider statute requires that the rider petition "shall include *all* of the utility's customers, including transport customers, to recover the revenue deficiency from a natural gas project."[258] This comports with the general principle that distribution upgrade projects should be recovered by all customers on the system, not just the customers served by the upgrade.

281. In contrast, there does not appear to be record support for the 50/50 split suggested by the Department. At the evidentiary hearing, Ms. Peirce clarified that there was no calculation behind the 50/50 split, but rather that it was where she "landed" in her attempt to "balance out the rate impact that . . . those two groups [Rochester and non-Rochester customers] would have in this revenue deficiency."[259] In addition, as discussed in Section II the Legislature determined that it would be reasonable for all customers to share in 33 percent of the costs of line extensions brought under the NGEP Rider. Assigning half of those costs back to the customers obtaining the new extension, so that only 16.5 percent of the costs are shared amongst all customers, may contravene the Legislature's intent in the NGEP Rider.

282. The evidence in the record demonstrates that the Commission should find that the Rochester Project proposed by MERC is not prudent, reasonable, or necessary to provide service to customers in the Rochester area. But if the Commission does approve the Rochester Project, the record supports MERC's proposal to recover the Phase II distribution costs from all customers.

[257] Tr. Evid. Hearing, Vol. 1, at 207–208 (Peirce).
[258] Minn. Stat. § 216B.1638 subd. 2(a) (2015) (emphasis added).
[259] Tr. Evid. Hearing, Vol. 1, at 206:7–19 (Peirce).

B. MERC's Phase II Cost Allocation Proposal Is Evidence That The Rochester Project Is Not Eligible For NGEP Rider Recovery.

283. The OAG also argued that the discussion about cost allocation are also relevant to another issue in this case—NGEP Rider eligibility. In particular, MERC's argument that the Rochester Project is a system integrity and reliability project, rather than a line extension project, demonstrate that the Project is not eligible for NGEP Rider recovery.

284. As the OAG argued, the Rochester Project is not the type of project envisioned by the Legislature when it enacted the NGEP rider statute. MERC states that the Rochester Project is a "system integrity and reliability project" that is "similar to other infrastructure projects included in rate base and recovered through base rates."[260] MERC further asserts that the Rochester Project "is not being undertaken to connect specific customers to our distribution system nor to extend the distribution system to new customers in an area that MERC is not already service."[261] For that reason, and for reasons discussed elsewhere, the Rochester Project is ineligible for recovery under the NGEP statute.

C. Interruptible Discounts Should Be Recalculated.

285. While the evidence in the record supports MERC's proposal to recover the Phase II distribution costs from all of its customers, there are problems identified by the OAG related specifically to interruptible customers.

286. Interruptible customers receive a discount to their distribution rates because of their agreement to curtail consumption when called to do so.[262] As described by Mr. Heinen, "interruptible customers receive the benefit of lower non-gas margins knowing that they will be interrupted if load must be curtailed to maintain system integrity.[263] For example, MERC's General Service Small C&I customers pay a distribution charge of $0.18116 per therm, and Large C&I customers currently pay a distribution charge of $0.16579 per therm.[264] In comparison, Small Volume Interruptible customers pay a distribution charge of $0.08490 per therm, and Large Volume Interruptible customers pay a distribution charge of $0.04553 per therm.[265] For the benefit they provide to the system, namely their agreement to curtail when it is necessary, the interruptible customers receive rate discounts of somewhere between fifty and seventy percent.

287. Agreeing to curtail in the face of high demand will not provide any benefit to the system in Rochester, however, because the Rochester Project will create so much excess capacity that it is extremely unlikely that customers' curtailment will be necessary. MERC agrees that "interruptible customers will receive the benefit of firmer service" if the Rochester Project is

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[260] Ex. 5, at 23 (Lee Direct).
[261] *Id.* at 24.
[262] Ex. 300, at 63 (Urban Amended and Corrected Direct).
[263] Ex. 405, at 9 (Heinen Direct).
[264] Minnesota Energy Resources Corporation Tariff Book, 4th Revised Sheet No. 5.00.
[265] *Id.*, 4th Revised Sheet Nos. 5.21 & 5.21.

constructed.[266] In other words, the benefits that interruptible customers provide to the system will be reduced, but the discount that they receive for their agreement will stay the same.

288. In addition, sophisticated customers will be aware that there will be a significant amount of excess capacity in the Rochester area. That means that they will know that they can transfer from firm to interruptible service with very little risk of facing curtailment. Every customer that does so will increase the cost burden on customers who are unable, aware, or do not have the option to transfer to interruptible service—like captive residential customers.

289. These concerns indicate that, if the Rochester Project moves forward, changes must be made to ensure that firm customers are treated fairly. Dr. Urban requested that MERC provide information about recalculating the interruptible discount in the face of such an extreme level of excess capacity.[267] MERC declined to provide a detailed discussion, but did agree that MERC's tariffs "be reviewed to ensure that interruptible customers are not allowed to 'free ride' on the system."[268] As such, it appears that MERC agrees that the Rochester Project may allow interruptible customers to free ride, or avoid sharing the full cost of the Project, but the Company has not offered any solution to the problem. Instead, the Company suggests that such issues be tabled until the Company's next rate case.

290. Whether these issues are handled in this proceeding or in a future rate case, the Commission should be aware of the problem and the fact that it must be addressed eventually. In addition, the Commission should consider the fact that these equity problems would not exist, or would be much less problematic, if the Rochester Project MERC proposed were sized more appropriately. A more moderate, phased or incremental approach, as discussed above, would mitigate many of the problems with equity between firm and interruptible customers, as well as the incentive customers will have to shift to interruptible service and concentrate the burden on the remaining firm customers.

D. THE COMMISSION SHOULD ENSURE THAT ALL CUSTOMERS SHARE COST BURDENS IN AN EQUITABLE MANNER IF THE ROCHESTER PROJECT IS BUILT.

291. In addition to the equitable problems with interruptible customers and distribution costs, there is an equity problem with MERC's proposal for NNG capacity costs.

292. MERC proposes to collect the estimated $58 million in costs from the NNG portion of the Rochester Project on a per-therm basis via the PGA commodity charge from system sales customers (firm and interruptible) in its NNG PGA area.[269] Under MERC's proposal, its transportation customers would not directly pay for NNG-related capacity costs and would only be paying "for their share of improvements to MERC's distribution system," or the

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[266] Ex. 6, at 40 (Lee Rebuttal).
[267] Ex. 300, at 63 (Urban Amended and Corrected Direct).
[268] Ex. 6, at 43 (Lee Rebuttal).
[269] *See Id.* at 29–30 (noting that the cost of NNG's capacity expansion would "generally [be] recovered via the demand portion of the PGA" but that "it would be possible for a portion of those costs to be allocated through the commodity portion of the PGA" in order to recover NNG costs from interruptible sales customers" who pay commodity, but not demand charges within the PGA).

Phase II distribution upgrade costs.[270] Transportation customers, unlike sales customers, obtain their natural gas from third parties. As a result, they do not share in the fuel costs that are recovered from the NNG-PGA, and so would not pay for any of the costs of the NNG upgrades that MERC proposes to recover through the PGA (in addition to any distribution rate discounts transportation customers will receive for agreeing to interruptible service).

293. While they would not share in the costs of the NNG upgrades, transportation customers *will* receive benefit from the newly available capacity if the Rochester Project is built. The new capacity of the NNG system will represent capacity that is available to transportation customers on any days that MERC is not utilizing all of the available capacity. For those customers that take interruptible service, there will be an extremely low likelihood of curtailment. And for all customers, there will be a new supply of natural gas capacity available to them. In fact, the amount of excess supply on the system may reduce prices in the capacity market.

294. Department witness Mr. Heinen raises similar concerns. In his Direct Testimony, Mr. Heinen stated that the new capacity on the NNG line "will be used to serve MERC's sales customers *and* its transportation customers," so it is "important to ensure that costs of expanding NNG's capacity are appropriately charged to both sales and transportation customers."[271] Mr. Heinen points out that the NGEP Statute requires that transportation customers share in the costs of projects recovered through the rider, and states that, "Without this provision in the NGEP statute, the Company's sales customers would unfairly subsidize transportation customers, who would not pay for the pipeline capacity costs associated with the Project."[272]

295. Mr. Heinen concluded, however, that transportation customers would be contributing "either directly or indirectly" to the costs of the NNG expansion because they will have to purchase their capacity through capacity markets. Mr. Heinen states that this may be a reasonable solution because he believes that "MERC should be able to obtain near full, or maximum, rate recovery in the capacity release market because third-party marketers, with which transportation customers contract, can only buy capacity deliverable in the Rochester area from MERC."[273] But all of MERC's statements regarding the capacity market indicate that Mr. Heinen's assumptions about capacity market prices are not reasonable.

296. First, during the evidentiary hearing Ms. Lee stated that MERC holds 85 to 90 percent of the existing capacity in the Rochester area.[274] While MERC will acquire 100 percent of the new capacity on the system, it is possible that existing marketers have long-term capacity contracts with NNG. If so, they will be able to serve transportation customers without having to work through MERC.

[270] *Id.* at 30.
[271] Ex. 405, at 49–50 (Heinen Direct).
[272] Ex. 407, at 11 (Heinen Surrebuttal).
[273] *Id.* at 13.
[274] Tr. Evid. Hearing, Vol. 1, at 36–37 (Lee).

297. Second, during the evidentiary hearing Ms. Lee also stated that the prices in the capacity release market are set according to market conditions.[275] In other words, MERC does not set the prices—they are set by supply and demand. And, as Mr. Heinen pointed out in his Direct Testimony, "the revenue associated with these releases is typically small compared to the original purchase price of the capacity."[276] In fact, Mr. Heinen pointed out that while "there is some relief to ratepayers … [the capacity release market] should not be considered a significant tool to mitigate costs."[277] There is reason to believe that the prices could be even lower in the future. The principles of supply and demand indicate that a significant amount of excess capacity in the market would depress prices, because marketers would know that there is far more supply than demand.

298. Transportation customers will share in the benefits if the NNG upgrades are built, but they would not share in the costs except to the extent that they are recovered through transactions on the capacity market. It is not reasonable to assume that the prices in the capacity release market will reflect the full benefit that transportation customers will receive.

299. In addition, the OAG noted a further concern that the amount of excess capacity may incentivize customers to switch to interruptible transportation service in order to avoid the costs of the Rochester Project to the maximum extent. As Ms. Lee pointed out, the Company's tariffs provide a limited ability to control what type of service customers take.[278] Mr. Heinen pointed out that the "excess capacity in the Rochester area will likely result in a decrease in curtailments and a drift to 'firmer' capacity" for interruptible customers.[279] Sophisticated firm service customers will be incentivized to transfer to interruptible or transportation service because they will know that it is very unlikely they will be curtailed. By doing so they will could completely avoid the costs of the NNG upgrade, and receive a discounted rate for all of MERC's distribution costs, including the Rochester Project. And by taking steps to reduce these costs for themselves, transportation would focus the costs all the more heavily on existing firm customers, including captive residential customers. In addition to raising concerns with cost allocations, the fact that the Rochester Project will incentivize customers to switch to discounted interruptible or transportation service is yet another factor that demonstrates that the Rochester Project is not reasonable and prudent.

300. Ultimately, all customers, including transportation customers, should contribute to the costs of the NNG portion of the Rochester Project in a manner commensurate with the benefits received. MERC's proposal would shield transportation customers entirely from the majority of Rochester Project costs, and the hope that capacity release markets will recoup some of the burden for firm customers is not reasonable. If the project is approved, the Company should be ordered to work with parties to ensure that the burden does not fall on MERC's firm

[275] *Id.* at 37:24–25.
[276] Ex. 405, at 47 (Heinen Direct).
[277] *Id.*
[278] Ex. 6, at 41 (Lee Rebuttal)
[279] Ex. 407, at 15 (Heinen Surrebuttal).

customers. Instead, the costs should be shared in an equitable manner between firm, interruptible, and transportation customers.[280]

IX. COST CAPS FOR THE ROCHESTER PROJECT.

301. In his Direct Testimony, Department witness Mr. Heinen proposed that the future cost recovery for the Rochester Project, if approved, should be limited "only to the amount of costs that the utility proposed in its petition," and that "the utility would have the burden of proof to show that any costs above the approved level are prudent and why it would be reasonable to recover such costs from ratepayers."[281] Mr. Heinen explained that such cost caps are important because "[u]tility cost estimates are used extensively throughout the regulatory process and are relied upon by the Commission, particularly when considering alternatives to a proposed project."[282] Mr. Heinen continued by noting that, "Absent cost recovery caps tied to the evidentiary record . . . utilities have little incentive to expend the effort needed to accurately report project costs in regulatory proceedings, nor to ensure that the actual costs are as reasonable as possible."[283] Mr. Heinen provided examples of other proceedings in which the Commission had applied such caps, and then recommended that the Commission cap the costs of MERC's distribution costs for the Rochester Project at the Company's estimate in this proceeding—$44,006,607.[284]

302. The Department's analysis is sound and its recommendation is reasonable. Accurate estimates are essential in order for the Commission to ensure that rates are just and reasonable. Capping costs at the level estimated in the initial petition will incentivize utilities to ensure that their estimates are reasonable, and to control costs once construction begins.

303. The OAG noted that it found some of Mr. Heinen's other statements to be concerning. In particular, later in his Direct Testimony, Mr. Heinen suggested that the Commission will "have the opportunity to review costs in future rider reviews and in subsequent general rate cases."[285] It is true that MERC must begin another proceeding to request recovery of costs through the NGEP Rider. But it would not be reasonable to defer a thorough investigation of the prudence and reasonableness of MERC's proposal to the future. First, it is unlikely that a future rider proceeding will be converted into a contested case—in this proceeding the Commission has the benefit of sworn testimony and extensive analysis that would be unusual for an annual rider proceeding. And, second, as a practical matter, once MERC has expended funds on infrastructure investments it would be much more challenging to deny recovery. *This* proceeding is the best avenue to review the prudence and reasonableness of the Rochester Project, and the Commission should not delay that investigation just because it will have another opportunity to review the Project in the future. The OAG, in its brief and in its filed testimony,

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[280] Given that MERC is seeking pre-approval of the Project in this proceeding, rather than immediate cost recovery, if the Commission orders the Company to develop a method for ensuring that costs are shared equitably between all customers classes there will be an opportunity to address the issue further in a future cost recovery proceeding.
[281] Ex. 405, at 40 (Heinen Direct).
[282] *Id.* at 41.
[283] *Id.*
[284] *Id.* at 43.
[285] *Id.* at 44.

has shown that the Rochester Project is not reasonable, prudent, and necessary to provide service to customers in the Rochester area.

CONCLUSION

304. Based on all of the evidence in the record, the Company has not demonstrated that the Project is prudent, reasonable, and necessary to provide service to customers in the Rochester area. The Commission should reject MERC's request for pre-approval of the Rochester Project.

305. The Rochester Project would produce far more natural gas capacity than is reasonable, decades before it will be useful.

306. The evidence demonstrates that the Company focused too heavily on the results of its flawed long-term peak demand forecast, and ultimately selected a Project that will place all of the forecasting risk and the risk of overbuilding on captive ratepayers.

307. The Rochester Project would lead to intergenerational inequities as a result of excess reserve margins, and incentivize large customers to avoid the costs of the Project by switching to interruptible or transportation service.

308. The record demonstrates that MERC did not consider phased or incremental approaches that could have provided significant benefit to customers, and also did not consider whether conservation or peak shaving facilities could reduce the need for additional capacity.

309. The Commission should also find that the Rochester Project is not eligible for recovery through the NGEP Rider.

310. The NGEP Rider Statute is ambiguous, and a careful review demonstrates that the Legislature did not intend the NGEP Rider Statute to apply to investments like the Rochester Project.

311. If the Commission approves the Rochester Project, the Commission should approve MERC's proposal for cost recovery regarding the Phase II distribution costs, but should order the Company to work with interested parties to ensure that the NNG costs are shared by all customers in a manner commensurate with the benefits received.

312. Finally, if the Project is approved the Commission should order a cost cap as recommended by the Department.

Dated: October 25, 2016

Respectfully submitted,

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October 25, 2016

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

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

Dear Judge Cochran:

Enclosed and e-filed in the above-referenced matter please find the PUBLIC and HIGHLY SENSITIVE TRADE SECRET Reply Brief of the Office of the Attorney General – Residential Utilities and Antitrust Division.

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

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

Sincerely,

s/ Ryan Barlow

RYAN P. BARLOW
Assistant Attorney General

(651) 757-1473 (Voice)
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Enclosure

AFFIDAVIT OF SERVICE

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

STATE OF MINNESOTA)
) ss.
COUNTY OF RAMSEY)

I hereby state that on October 25, 2016, I filed with eDockets the PUBLIC and HIGHLY SENSITIVE TRADE SECRET ***Reply Brief of the Office of the Attorney General – Residential Utilities and Antitrust Division*** and served the same upon all parties listed on the attached service list by email, and/or United States Mail with postage prepaid, and deposited the same in a U.S. Post Office mail receptacle in the City of St. Paul, Minnesota.

s/ Judy Sigal
Judy Sigal

Subscribed and sworn to before me
this 25th day of October, 2016.

s/ Patricia Jotblad
Notary Public

My Commission expires: January 31, 2020.

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