OAH 68-2500-33191
MPUC G-011/M-15-895

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

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

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION

TABLE OF CONTENTS

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FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION

This matter came before Administrative Law Judge Jeanne M. Cochran for an evidentiary hearing on September 6-7, 2016 in the Small Hearing Room of the Minnesota Public Utilities Commission (Commission or PUC). Public hearings were held on July 12-16, 2016, and written comments were received until July 28, 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 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 Company (NNG or Northern).

Andrew P. Moratzka and Emma J. Fazio, Stoel Rives, LLP, appeared on behalf of the Super Large Gas Intervenors (SLGI).

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

STATEMENT OF THE ISSUES

On October 26, 2015, MERC filed its petition for evaluation and approval of rider recovery (Petition) for its Rochester Natural Gas Extension Project (Rochester Project or Project).[1] MERC submitted its petition pursuant to the natural gas extension project (NGEP) statute, Minn. Stat. § 216B.1638 (2016).[2] This statute was enacted in 2015.[3] MERC's petition is the first petition to be filed under this recently enacted statute. [4]

On February 8, 2016, the Commission issued its Notice and Order for Hearing referring the matter to the Office of Administrative Hearings for contested case proceedings.[5] The Notice and Order for Hearing set forth the following issues to be addressed by the parties:[6]

> 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 [percent] renewable energy by 2031?
>
> 2. Is it reasonable to recover the Rochester Project costs from all of MERC's ratepayers?
>
>   a. If so, on what basis;
>
>   b. If not, what other allocation method would be more reasonable?
>
> 3. What other funds may be available to cover the project costs?

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

The Administrative Law Judge concludes that MERC has shown by a preponderance of the evidence that the Rochester Project is necessary, reasonable, and prudent. The Administrative Law Judge also concludes that the Project is eligible for rider recovery under the NGEP statute.

The Administrative Law Judge recommends that the Commission issue an order approving the Project and the proposed NGEP rider, subject to the conditions set forth below. The Administrative Law Judge also recommends that the Commission approve MERC's cost recovery proposal.

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[1] Exhibit (Ex.) 1 (Petition); NOTICE AND ORDER FOR HEARING at 1 (Feb. 8, 2016) (eDocket No. 20162-118054-01).
[2] Ex. 1 at 1 (Petition).
[3] 2015 Minn. Laws. 1st Spec. Sess. ch. 1, art. 3, § 20 at 57.
[4] NOTICE AND ORDER FOR HEARING at 1 (eDocket No. 20162-118054-01).
[5] *Id.* at 1, 4.
[6] *Id.* at 5.

Based on the evidence in the hearing record,[7] the Administrative Law Judge makes the following:

FINDINGS OF FACT

I. Overview of the Petition

1. In its Petition, MERC seeks a determination that the Rochester Project is reasonable and prudent. It also requests authorization from the Commission to establish a rider pursuant to the NGEP statute to recover a portion of the Project costs.[8]

2. The NGEP statute provides that the Commission "shall approve a public utility's petition for a rider to recover the costs of a natural gas extension project if it determines that: (1) the project is designed to extend natural gas service to an unserved or inadequately served area; and (2) project costs are reasonable and prudently incurred."[9] An "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."[10]

3. The NGEP statute also provides that no more than 33 percent of an approved project's costs can be recovered through a NGEP rider.[11] The remainder of the costs would be recovered through the utility's base rates established in one or more rate cases.[12]

4. According to the Petition, MERC's natural gas distribution system is currently at capacity in the Rochester area and must be upgraded to meet current needs as well as expected growth in customer demand.[13] The Project includes two phases (Phase I and Phase II), which involve improvements to MERC's distribution system.[14] As part of the Project, MERC also plans to acquire additional interstate pipeline capacity for delivery to its Rochester distribution system.[15]

5. Phase I of the Project was completed in 2015.[16] Phase I cost approximately $5.6 million, and involved improvements to MERC's delivery system in the Rochester

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[7] A Master Exhibit List, including links to all exhibits received into evidence, was e-filed by the court reporter on October 11, 2016 (eDocket No. 201610-125558-01).
[8] Ex. 1 (Petition).
[9] Minn. Stat. § 216B.1638, subd. 3(b).
[10] *Id.*, subd. 1(i) (2016).
[11] *Id.*, subd. 3(c).
[12] *See* Minn. Stat. § 216B.16 (2016).
[13] Ex. 1 at 1 (Petition).
[14] *Id.* at 1-5; Ex. 5 at 2 (Lee Direct).
[15] Ex. 1 at 2 (Petition).
[16] *See* NOTICE AND ORDER FOR HEARING at 3, 5, 8 (eDocket No. 20162-118054-01); Ex. 5 at 4 (Lee Direct).

area.[17] The Commission authorized recovery of the Phase I costs in MERC's most recent rate case.[18]

6. Phase II of the Project consists of changes to MERC's local distribution system, which are expected to be completed by 2023.[19] This phase involves upgrading MERC's town border station (TBS) system and constructing a new 13-mile long high-pressure pipeline that will tie together the northern and southern portions of the TBS system.[20]

7. MERC has requested approval of the Phase II costs, which are estimated to total about $44 million. MERC seeks to recover 33 percent of the Phase II costs from all of MERC's ratepayers through future NGEP rider filings, with the balance of the Phase II costs recovered in future rate cases.[21]

8. In addition, MERC has contracted with its wholesale natural gas supplier, NNG, to build new infrastructure that will supply MERC with increased interstate pipeline capacity. In its Petition, MERC requested Commission approval of the NNG costs, which MERC stated would total approximately $55 million on a net present value (NPV) basis.[22] MERC has proposed to recover these NNG costs through MERC's Purchased Gas Adjustment (PGA) mechanism.[23]

II. Parties to the Proceeding

9. MERC is a local distribution company that provides retail natural gas service to approximately 230,000 customers in 184 communities in Minnesota.[24] MERC is a subsidiary of WEC Energy Group, Inc. (WEC), a utility holding company headquartered in Milwaukee, Wisconsin.[25] MERC will construct, own, and operate the natural gas distribution infrastructure of the Rochester Project.[26]

10. The Department advocates for the public interest in utility proceedings.[27] The Department staff files testimony and argument addressing the reasonableness of the utility's request.

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[17] Ex. 1 at 1 (Petition); Ex. 5 at 4 (Lee Direct).
[18] *See* Ex. 5 at 2, 4 (Lee Direct); *In re Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Natural Gas Serv. in Minn.*, MPUC Docket No. G-011/GR-15-736, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 8, 54 (Oct. 31, 2016).
[19] Ex. 1 at 1-2 (Petition); Evidentiary Hearing Transcript Volume (Tr. Vol.) 1 at 57-58 (Lyle).
[20] Ex. 1 at 1-2 (Petition).
[21] *Id.* at 4.
[22] *Id.* at 5.
[23] *Id.* at 5; Ex. 5 at 4-5 (Lee Direct).
[24] Ex. 1 at 6 (Petition).
[25] Ex. 5 at 1 (Lee Direct).
[26] Ex. 1 at 6 (Petition).
[27] *See* Minn. Stat. § 216A.07, subds. 2-3 (2016).

11. The OAG advocates for the interests of residential and small business customers in proceedings before the Commission.[28] The OAG staff submits its own testimony and argument intended to protect those interests.

12. 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, the Minntac and Keewatin Mines of United States Steel Corporation, and USG Interiors, Inc.[29]

13. NNG is an interstate natural gas transmission company. It operates more than 14,700 miles of pipeline in 11 states, with more than 3,340 of those miles in Minnesota. NNG transports gas pursuant to the federal Natural Gas Act and operates under the jurisdiction of the Federal Energy Regulatory Commission (FERC). NNG delivers natural gas to MERC at 176 town border stations and 1,815 farm taps in the state.[30] NNG will construct, own, and operate the interstate transmission infrastructure that will provide the additional interstate capacity contracted for by MERC.[31]

III. Jurisdiction

14. The Commission has general jurisdiction over MERC's rates under Minn. Stat. §§ 216B.01 and 216.03 (2016). The Commission has specific jurisdiction over requests for rider recovery of natural gas extension project costs under Minn. Stat. § 216B.1638.

15. 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

16. On September 30, 2015, MERC filed its general rate case in Docket No. G011/GR-15-736. In its rate case filing, it proposed to recover Rochester Project Phase I costs of approximately $5.6 million and a portion (approximately $600,000) of Phase II costs, for a total of $6.2 million.[32]

17. On October 26, 2015, MERC filed its petition for evaluation and approval of rider recovery for the Rochester Project.[33]

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[28] *See* Minn. Stat. § 8.33 (2016).
[29] SLGI Petition to Intervene at 1-3 (Apr. 19, 2016) (eDocket No. 20164-120321-03).
[30] NNG Petition to Intervene at 1 (Feb. 16, 2016) (eDocket No. 20162-118339-01).
[31] Ex. 1 at 6 (Petition).
[32] *In re Application of Minn. Energy Res. Corp. for Auth. To Increase Rates for Natural Gas Serv. in Minn.*, MPUC Docket No. G011/GR-15-736, INITIAL FILING (Sept. 30, 2015).
[33] Ex. 1 at 1 (Petition). In October 2014, about a year before filing its Petition, MERC notified the Department of its need for expansion in the Rochester area. The goals of the Project have not changed since the October 2014 notification, but the Company's current plan to increase capacity differs from the potential projects the Company presented to the Department in the planning phase. For example, in its October 2014 presentation, the Company stated that it anticipated total Project costs upwards of $170 million, not

18. On November 3, 2015, the Commission issued a Notice of Comment Period on Procedures in which it requested comments on the review process to be used for MERC's petition.[34]

19. MERC, the Department, the OAG, and NNG each filed comments on the process.[35] The Department and the OAG filed reply comments. In addition, MERC filed a response to the Department's reply.[36]

20. On February 8, 2016, the Commission issued the Notice and Order for Hearing in this matter. In its order, the Commission referred MERC's Petition to the Office of Administrative Hearings for a contested case proceeding, and moved all Rochester Project Phase II costs and issues from the ongoing rate case to this docket. The Commission also requested that the Administrative Law Judge hold public hearings in Rochester and other locations within MERC's service area. In addition, the Commission 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 so as to facilitate their ability to participate in developing the record.[37]

21. In its order, the Commission noted that the parties to the proceeding, at that time, were MERC, the Department, and the OAG. The order notified other persons wishing to become formal parties to file a petition to intervene with the Administrative Law Judge.[38]

22. On February 16, 2016, NNG filed a petition to intervene.[39]

23. On February 19, 2016, the Administrative Law Judge issued a Notice of Prehearing Conference.

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

25. On March 9, 2016, the Administrative Law Judge issued the First Prehearing Order. The First Prehearing Order granted NNG's petition to intervene, set procedures for parties in the case, and established the following schedule:

Milestone	Due Date
MERC Direct Testimony	April 15, 2016

including contingencies, which is greater than the approximately $100 million in projected costs described in this Docket. Ex. 405 at 4-5 (Heinen Direct).

[34] NOTICE OF COMMENT PERIOD ON PROCEDURES (Nov. 3, 2015) (eDocket No. 201511-115403-01).
[35] NOTICE AND ORDER FOR HEARING at 2 (eDocket No. 20162-118054-01).
[36] *Id.*
[37] *Id.* at 8.
[38] *Id.* at 7.
[39] NNG Petition to Intervene at 1 (Feb. 16, 2016) (eDocket No. 20162-118339-01).

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

26. The City of Rochester, Mayo Clinic, and the Destination Medical Center governing board were each added to the service list and served with the First Prehearing Order.[40]

27. On March 9, 2016, the Administrative Law Judge issued a Protective Order governing the use of trade secret information and other nonpublic data.[41]

28. On April 14, 2016, the Administrative Law Judge issued the Highly-Sensitive Trade Secret Protective Order to facilitate the disclosure of highly-sensitive third-party bidding and commercial information that MERC utilized in analyzing bids for adding interstate pipeline capacity to its distribution system in and around Rochester.[42]

[40] *See* FIRST PREHEARING ORDER, Certificate of Service (Mar. 9, 2016) (eDocket No. 20163-119023-01).
[41] PROTECTIVE ORDER (Mar. 9, 2016) (eDocket No. 20163-119024-01).
[42] HIGHLY-SENSITIVE TRADE SECRET PROTECTIVE ORDER (Apr. 14, 2016) (eDocket No. 20164-120102-01).

29. On April 15, 2016, MERC filed direct testimony.

30. On April 19, 2016, SLGI filed a petition to intervene.[43] MERC did not object to the intervention of SLGI as a party to this matter.[44]

31. On May 2, 2016, the Administrative Law Judge issued an order granting intervention to SLGI.

32. No petition to intervene was filed by the City of Rochester, Mayo Clinic, or the Destination Medical Center by the May 16, 2016 deadline.

33. On July 1, 2016, the Department and the OAG each filed direct testimony from their witnesses. NNG and SLGI did not file direct testimony.

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

- Rochester City Hall, Kahler Apache Hotel, Rochester, Minnesota, July 12, 2016 at 1:00 p.m. and 6 p.m.

- Albert Lea City Hall, City Council Chambers, Albert Lea, Minnesota, July 13, 2016 at 6:00 p.m.

- Steeple Center, Assembly Hall, Rosemount, Minnesota, July 14, 2016 at 1:00 p.m.

- Cloquet City Hall, 1307 Cloquet Avenue, July 15, 2016 at 1 p.m.

35. On July 28, 2016, the period for written public comments closed.

36. Also on July 28, 2016, the Department, the OAG, and MERC each filed rebuttal testimony. NNG and SLGI did not file rebuttal testimony.

37. On August 25, 2016, the Department, the OAG and MERC each filed surrebuttal testimony. NNG and SLGI did not file surrebuttal testimony.

38. On September 1, 2016, a prehearing conference was held with the parties by telephone to discuss hearing procedures and other related items.

39. On September 6-7, 2016, the evidentiary hearing was held in the Commission's Small Hearing Room in St. Paul, Minnesota. On Friday September 2, 2016, counsel for NNG notified the Administrative Law Judge that NNG would not be attending the evidentiary hearing.[45]

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[43] SLGI Petition to Intervene (Apr. 19, 2016) (eDocket No. 20164-120321-03).
[44] MERC Letter to Administrative Law Judge (Apr. 20, 2016) (eDocket No. 20164-120385-01).
[45] *See* Tr. Vol. 1 at 10.

40. On October 11, 2016, all parties except NNG filed initial briefs.[46]

41. On October 25, 2016, all parties except NNG and SLGI filed reply briefs.

42. In addition, on October 25, 2016, Minnesota House Representative Pat Garofalo filed a letter with the Commission urging the Commission to approve the Project and stating that, in his view, the project is consistent with the NGEP statute.[47]

V. Summary of Public Comments

43. Approximately 21 people attended the five public hearings, with 12 offering comments.[48] In addition, over 40 written comments were received from individuals, businesses, and government entities either via the Commission's *SpeakUp!* webpage or U.S. mail by the July 28, 2016 deadline.[49]

44. A number of individuals raised concerns with the proposed Rochester Project. Several expressed concerns about the burden of additional rate increases on low-income customers and customers living on a fixed income. Still others expressed concerns about current customers being asked to pay for infrastructure costs that are designed to meet the needs of future customers. A number suggested that the costs of the Project should be borne only by customers in the Rochester area, the primary beneficiaries of the Project. Some customers also questioned the need for the Project.

45. One individual customer, a retired engineer, provided comments in support of the Project. He stated that the Project is important for reliability purposes.[50]

46. A number of businesses and governmental entities in the Rochester area provided comments in support of the Project, whereas business leaders in the Albert Lea area raised concerns about the impact of a rate increase on the local economy.

47. A complete summary of the public comments is included as Attachment A to this report.

VI. Legal Standard

48. The NGEP statute provides that the Commission: "shall approve a public utility's petition for a rider to recover the costs of a natural gas extension project if it determines that: (1) the project is designed to extend natural gas service to an unserved

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[46] SLGI's brief addressed only one issue, the recovery of costs for the new interstate pipeline capacity to be provided by NNG.
[47] Letter from Rep. Pat Garofalo (Oct. 25, 2016) (eDocket No. 201610-125988-02).
[48] *See* Sign In Sheet Rochester 1:00 p.m. Public Hearing (July 12, 2016); Sign In Sheet Rochester 6:00 p.m. Public Hearing (July 12, 2016); Sign In Sheet Albert Lea Public Hearing (July 13, 2016); Sign In Sheet Rosemount Public Hearing (July 14, 2016); Sign In Sheet Cloquet Public Hearing (July 15, 2016).
[49] Public Comments (July 29, 2016) (eDocket No. 20167-123732-01); Public Comments (July 29, 2016) (eDocket No. 20167-123755-01); Public Comments (Aug. 24, 2016) (eDocket No. 20168-124373-01).
[50] Comment by Thomas DeBoer (July 23, 2016) (eDocket No. 20168-124373-01).

or inadequately served area; and (2) project costs are reasonable and prudently incurred."[51]

49. In making the determination, the Commission must consider the requirement that rates must be reasonable, as well as the statutory requirement that utilities provide safe and reliable service.[52]

50. MERC has the burden of proof to show that the Rochester Project is necessary, reasonable, and prudent, and to demonstrate that the Project meets the requirements for cost recovery through a NGEP rider.[53]

VII. General Overview of MERC's Stated Need for the Project

51. MERC is the sole provider of retail natural gas service to Rochester and surrounding communities. [54]

52. MERC serves three types of customers: firm, interruptible, and transportation. Firm customers have the right to receive gas service from MERC all of the time, including at peak demand. Interruptible customers have a lower priority than firm customers; they receive gas at a reduced rate in exchange for agreeing to curtail their service when called upon to do so by the Company. Transportation customers receive only distribution transportation service from MERC. They do not purchase gas from MERC. Instead, they arrange to have their gas commodity delivered on the interstate pipeline system to MERC's distribution system by a third party marketer or other source. MERC can curtail the service of transportation customers.[55]

53. The Rochester area and southeastern Minnesota have experienced continued population growth, including industrial and residential expansion, in recent years. This expansion is due in part to expanding health care facilities in and around Rochester.[56] The growth has reached a point where MERC now has a limited ability to provide firm and reliable natural gas service to existing customers and new customers.[57]

54. For example, during the Polar Vortex of January 2014, MERC exceeded its total firm contracted capacity at Rochester TBS 1D.[58] In addition, in the Rochester area as a whole, MERC utilized nearly 100 percent of its contracted firm capacity of 55,169 Dekatherms (Dth or Dkt) after curtailing its transport and interruptible customers in the

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[51] Minn. Stat. § 216B.1638.
[52] Minn. Stat. §§ 216B.03-.04 (2016).
[53] *See* Minn. R. 1400.7300, subp. 5 (2015); *In re Commission Investigation into Xcel Energy's Monticello Life-Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, MPUC Docket No. E-002/CI-13-754, ORDER FINDING IMPRUDENCE, DENYING RETURN ON COST OVERRUNS, AND ESTABLISHING LCM/EPU ALLOCATION FOR RATEMAKING PURPOSES at 12-13 (May 8, 2015).
[54] Ex. 1 at 7 (Petition).
[55] Tr. Vol. 1 at 22-23 (Lee); *see* Ex. 1 at 19 (Petition).
[56] Ex. 1 at 2, 19 (Petition).
[57] *Id.*; Ex. 5 at 8-9 (Lee Direct).
[58] Department's Reply Brief (Br.) at 1 (Oct. 25, 2016) (eDocket No. 201610-125979-01) (citing Ex. 1 at 2 (Petition), Ex. 12 at 6-7 (Mead Direct)).

area. The curtailment included St. Mary's Hospital, Franklin Heating Station, and Rochester Public Utilities in Rochester as well as interruptible customers in nearby communities.[59]

55. The Company's main barrier to providing firm, reliable natural gas service in the Rochester area is the limited interstate pipeline capacity that currently exists in the area. NNG is the sole provider of interstate natural gas pipeline capacity to the Rochester area. NNG is currently fully subscribed on its pipeline transmission system in the Rochester area, with no additional existing capacity available for purchase.[60]

56. Because of the shortage in firm upstream interstate pipeline capacity, MERC is unable to accommodate the growth in demand in the area. This capacity constraint also could prevent MERC from reliably serving its existing firm customers in the Rochester area if cold weather results in MERC exceeding its peak-day capacity.[61]

57. In addition, MERC's distribution system has operating pressure and piping configuration issues that prevent MERC from efficiently and reliably distributing all of the gas that is available. More specifically, under present circumstances in situations of very high demand, MERC's existing low-pressure distribution system in Rochester cannot distribute all of the gas supply available in the southern portion of the system to the northern portion of the system where it is needed. This constraint during peak periods is due to the configuration of the system's distribution piping that interconnects the various portions of MERC's low-pressure distribution system within the City of Rochester and the wide range of pressures under which the distribution system operates.[62]

58. MERC expects that demand for natural gas in the Rochester area will continue to grow in the coming years. This is due in part to the Mayo Clinic's $6 billion plan to become a destination medical center (DMC) for the United States and the world. Mayo announced its DMC plan in January 2013. Projections of the number of new jobs associated with the Mayo's DMC plan range from 35,000 to 45,000 over twenty years.[63]

59. In 2013, after the announcement of the DMC plan, the Minnesota legislature earmarked approximately $585 million in state and local funds to help pay for facilities and infrastructure specified in the legislation.[64]

60. To meet anticipated increased demand and address existing peak capacity issues, MERC developed a sales forecast for the Rochester area. MERC's forecast projects an increase in the Company's customer base in the Rochester area of approximately 20 percent over the next 10 years, from 2016 to 2025.[65] MERC expects

[59] Ex. 1 at 19 (Petition).
[60] *Id.*; Ex. 5 at 12 (Lee Direct).
[61] Ex. 1 at 19 (Petition).
[62] Ex. 5 at 11 (Lee Direct).
[63] Ex. 1 at 19-20 (Petition).
[64] *See* Minn. Stat. §§ 469.40-.47 (2016).
[65] Ex. 1 at 20 (Petition); Ex. 9 at 3 (Clabots Direct).

Rochester area retail therm sales to grow 1.5 percent per year on average over each of the next 10 years.[66]

61. To address the existing interstate capacity constraint and meet future demand, MERC evaluated a number of alternatives including: take no action; conservation; distribution system upgrade options; and adding interstate pipeline capacity.[67] MERC also considered peak shaving as an alternative, but not in the same level of detail as the other alternatives.[68] MERC determined that additional interstate capacity and upgrades to MERC's distribution system are necessary to address both existing capacity issues and future needs.[69]

62. On January 5, 2015, MERC issued a Request for Proposals (RFP) to obtain bids for additional interstate capacity to meet its forecast. MERC issued the RFP to all of the active pipeline companies operating in the general vicinity of Rochester, Minnesota.[70] MERC received responses from three pipeline companies.[71] MERC evaluated the proposals and ultimately entered into a contract with NNG for an additional 45,000 Dekatherms per day (Dth/day) of firm capacity on NNG's pipeline into the Rochester area.[72]

63. NNG's construction costs for adding the 45,000 Dth/day and upgrading its pipeline system into the Rochester area is about $55-60 million. MERC's Phase II distribution upgrades are estimated to cost approximately $44 million. The total capital commitment by MERC's customers for Phase II and the NNG costs is about $100 million.[73]

64. The Department and the OAG both reviewed MERC's forecast, MERC's analysis of alternatives, the RFP, MERC's contract with NNG, and MERC's planned distribution upgrades. The Department and the OAG also conducted extensive discovery and analysis of MERC's proposed Rochester Project.[74]

65. The Department identified issues with MERC's forecast, but ultimately agreed with MERC that the Rochester area is constrained as described above. The Department also concluded that, in its view, the size of the Rochester Project is reasonable and represents the best means of meeting current and expected demand in the Rochester area.[75]

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66 Ex. 9 at 3 (Clabots Direct).
67 Ex. 1 at 26-28 (Petition); Ex. 12 at 8-9 (Mead Direct).
68 Ex. 8 at 7-9 (Lyle Rebuttal) Tr. Vol 1 at 63-64 (Lyle).
69 Ex. 1 at 1-2 (Petition); Ex. 12 at 8-9 (Mead Direct); Ex. 40 at 9-10 (Sexton Direct).
70 Ex. 17 at 38 (Sexton Direct).
71 *Id.* at 41.
72 Ex. 12 at 11-12 (Mead Direct).
73 Ex. 5 at 15, 19 (Lee Direct).
74 *See* Exs. 300-314, 400-410 (OAG and DOC Witness Testimony and Attachments).
75 Department's Initial Br. at 44 (Oct. 11, 2016) (eDocket No. 201610-125576-01); Ex. 405 at 58-59 (Heinen Direct).

66. The OAG, on the other hand, concluded that MERC had failed to demonstrate that the Rochester Project is reasonable, prudent, and necessary.[76] The OAG identified a number of issues with MERC's forecast. In addition, the OAG raised concerns about MERC's RFP process and its consideration of alternatives.[77] In the OAG's view, the Rochester Project is much larger than necessary.[78] The OAG recommended that MERC take a more phased expansion path to meet existing and future needs in the Rochester area. In the alternative, if the Commission finds the Project is reasonable, the OAG recommended that a portion of the costs of the Project not be recoverable until that portion is actually needed by MERC's customers.[79] A more detailed discussion of the parties' positions on the need and reasonableness of the Rochester Project is set forth below.[80]

VIII. Evaluation of the Need, Reasonableness, and Prudence of the Proposed Rochester Project

A. MERC's Forecasted Need

67. MERC plans its system to meet the peak demand of its firm customers.[81]

68. The current firm capacity that MERC has contracted for into Rochester is 55,169 Dth/day.[82]

69. In determining whether the available capacity is sufficient to meet the gas needs of its firm customers, MERC estimates the amount of gas it will need to serve its firm customers at peak demand on the coldest possible day. This is known as the Design Day. MERC then compares the Design Day capacity amount to the amount of capacity available under contract to determine if it has sufficient capacity to meet the Design Day requirements into the forecasted period.[83]

70. MERC's Design Day estimate does not include the load of interruptible customers or transportation customers, only firm sales customers (Residential, Small Commercial and Industrial (C&I), and Large C&I).[84] Interruptible customers are not included in the Design Day estimate because they have agreed to have their service interrupted at times when there is insufficient capacity to meet the needs of both interruptible and firm customers, such as during extremely cold weather. In return, interruptible customers receive a discounted rate. Transportation load is also not included in estimates of peak demand for Design Day purposes because these customers procure their natural gas entitlement level from a third party vendor, not MERC.[85]

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[76] OAG Initial Br. at 6-8, 76 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
[77] *Id.* at 8, 76.
[78] *Id.* at 76-77.
[79] Ex. 311 at 24-25 (Urban Amended Surrebuttal).
[80] SLGI and Northern did not take a position on need for and reasonableness of the Rochester Project.
[81] Tr. Vol. 1 at 26 (Lee).
[82] Ex. 12 at 11 (Mead Direct).
[83] *See* Ex. 12 at 11, 21 (Mead Direct); Tr. Vol. 1 at 24 (Lee).
[84] Tr. Vol. 1 at 24 (Lee).
[85] Ex. 405 at 9 (Heinen Direct); *see* Tr. Vol. 1 at 26 (Lee).

71. In the 2015/2016 heating season, MERC estimated its Design Day need for Rochester was 60,929 Dth/day, which is 5,760 Dth/day more than the currently available capacity.[86] As a result, MERC's reserve margin during the 2015/2016 winter heating season was negative 9.5 percent. The reserve margin calculates the excess or shortfall of available capacity compared to the Design Day estimate of peak demand.[87]

72. To determine the anticipated future Design Day need in the Rochester area, MERC developed a sales forecast for the greater Rochester area, comprised of Olmsted County and the Dodge County communities of Kasson and Blooming Prairie.[88] MERC then used the forecasted annual growth in retail sales to estimate the annual growth in its Design Day.[89]

73. MERC utilized standard forecasting methodologies and statistically significant inputs in preparing its models.[90] The methodology used was mainly the Ordinary Least Squares (OLS) procedure: using monthly binaries, time trend, heating degree days, and economic and demographic variables including lagged variables where necessary. The models also incorporated various seasonal and autoregressive components where needed to correct for seasonality and serial correlation in the data patterns. The OLS forecast period was from 2015 through 2025. The forecasts were built on historical data from January 2007 through July 2015. The normal weather variable, 7,842 Heating Degree Days (HDD), was based on a rolling 20-year average, between 1995 and 2014, for MERC's NNG Purchased Gas Adjustment (PGA).[91]

74. A monthly customer count model and a use-per-customer model were used to derive total sales by class, with the final models for the Residential class and the Small C&I class adjusted based on "*a priori*" information. The *a priori* information related to expected sales growth among the customer classes, internal MERC projections, and potential peak day requirements based on local demographic data.[92] The *a priori* information relating to Rochester's future growth was used to corroborate the reasonableness of the results of MERC's forecast modeling. While MERC did consider this *a priori* information as a reasonableness check, MERC "did not incorporate growth assumptions specific to the DMC program" in its Rochester sales forecast.[93]

75. MERC noted that the Rochester area has historically grown at a higher rate than MERC's total system area, and MERC's anticipates that this trend will continue or possibility even accelerate as health care and other developments occur in the region.[94] According to MERC witness Amber Lee, Rochester's historically robust growth is likely to

[86] Ex. 12 at 11 (Mead Direct).
[87] *Id.* at 21.
[88] Ex. 9 at 3-4 (Clabots Direct).
[89] *See* Ex. 12 at 21 (Mead Direct).
[90] Ex. 26 at 1 (Clabots Opening Statement).
[91] Ex. 9 at 4 (Clabots Direct).
[92] Ex. 1 at 21 (Petition); Ex. 9 at 13 (Clabots Direct).
[93] Ex. 9 at 14 (Clabots Direct); Ex. 10 at 6-7 (Clabots Rebuttal).
[94] Ex. 9 at 10-12 (Clabots Direct).

continue because Rochester is a regional center for industry, agriculture, and health care.[95]

76. The results of MERC's sales forecast showed that retail sales for firm customers (Residential, Small C&I, and Large C&I) in the Rochester area would grow at an average annual rate of 1.6 percent. This forecast used weighted weather data from the MERC NNG PGA. The forecast was updated at the request of the Department to incorporate Rochester-specific weather. With this change, MERC revised its estimated annual sales growth rate in the Rochester area downward slightly to 1.5 percent.[96]

77. This estimate included only retail sales customers who receive firm service. The estimate does not include interruptible or transport customers.[97]

78. MERC then used the 1.5 percent forecasted growth rate in firm retail sales to estimate the yearly growth rate of its Design Day. Based on the results of MERC's forecast, MERC assumed that the Design Day requirement would also increase by 1.5 percent per year.[98] In other words, the expected growth in firm peak demand for the Rochester area was driven by the results of MERC's forecast of the firm rate class sales.[99]

79. Using this method, the Rochester Design Day of 60,929 Dth/day in 2015/2016 is estimated to increase to 87,097 Dth/day in the winter of 2039/2040. Looking out to the winter of 2042/2043, MERC estimates that its Rochester Design Day will increase to about 91,000 Dth/day.[100]

80. MERC used the projected 2042/2043 Design Day of about 91,000 Dth/day to determine the amount of capacity to plan for in 2042/2043. MERC added a five (5) percent reserve margin, which converts the capacity requirement to about 96,000 Dth/day. MERC then rounded this number up to 100,000 Dth/day for use in its Request for Proposals (RFP).[101]

1. The Department's Analysis of MERC's Forecasted Need

81. The Department noted that natural gas utilities do not typically produce medium- to long-range forecasts for purposes of utility regulation. Unlike electric utilities in Minnesota, which are required to regularly file integrated resource plans, Minnesota's regulated natural gas utilities are not subject to Commission review of their long-range expansion plans, procurement plans, or expected growth.[102]

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[95] Ex. 5 at 14 (Lee Direct). Ms. Lee is MERC's Manager of Regulatory and Legislative Affairs. *Id.* at 1.
[96] Ex. 9 at 7-8 (Clabots Direct).
[97] *Id.* at 8-9.
[98] *See* Ex. 12 at 21 (Mead Direct); Ex. 405 at 6 (Heinen Direct).
[99] Ex. 405 at 6 (Heinen Direct).
[100] Ex. 12 at 21 (Mead Direct) (Table 1, Rochester Design Day column); Ex. 17 at 40 (Sexton Direct). The actual projection for 2042/2043 using a 1.5 percent growth rate is 91,075 Dth/Day.
[101] Ex. 17 at 40 (Sexton Direct).
[102] Ex. 405 at 7 (Heinen Direct); *see also* Minn. Stat. § 216B.2422 (2016); Minn. R. ch. 7842 (2015).

82. The Department's witness, Adam Heinen, reviewed the Company's sales forecast and was able to replicate MERC's regression results using MERC's input data and model specifications.[103]

83. After reviewing MERC's model and inputs, the Department identified several concerns with the Company's methodology that could call into question the validity of the Company's need analysis. These concerns are discussed in more detail below.[104]

84. The Department then conducted an alternative need forecast. Based on its forecast, the Department concluded that MERC's forecasted need was appropriate, but likely represented an optimistic view of growth. The Department viewed its forecast as a base case or "status quo" estimate of expected demand.[105]

a. MERC's Projected Sales Growth

85. The Department's first concern with MERC's forecast related to MERC's projected sales growth.

86. MERC's estimates of sales growth were based upon forecasted customer count growth and use-per-customer.[106]

87. The results of the Company's customer count forecast suggested that the customer count would increase significantly, over time, into the forecast period. According to the Department, MERC's forecast assumed annual residential customer count growth in the Rochester area of approximately 2.26 percent. MERC also provided population forecasts from the Rochester-Olmsted Council of Governments in its Direct Testimony.[107]

88. The Rochester-Olmsted Council of Governments' population forecast data did not anticipate growth at the level projected by the Company. The highest average annual population growth assumed for Olmsted County was approximately 1.50 percent. Population growth estimates and customer count estimates are not entirely comparable. Population looks at the number of people in an area, while customer counts look at the number of utility meters in an area.[108]

89. The Department tested the reliability of the population growth data by comparing the results of MERC's residential customer count forecast to historical

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[103] Ex. 405 at 13 (Heinen Direct). Mr. Heinen has a Masters in Applied Economics, and has been a Public Utilities Rates Analyst with the Department since 2007. *Id.* at 1, AJH-1.
[104] *Id.* at 13.
[105] *Id.* at 5.
[106] *Id.* at 14.
[107] *Id.* at 15, AJH-9 (citing Ex. 9, DWC-2 at 7 (Clabots Direct)).
[108] *Id.* at 15-16.

household data because, in many respects, customer counts for a utility are analogous to the number of households in an area.[109]

90. The Department used historical household data for Olmsted County Minnesota for 1970 to 2010 from the 2010 Census, and household data for 1990 to 2014 from the State Demographer to estimate historical household growth for the Rochester Area.[110]

91. The Department compared these historical household counts to historical population numbers to determine whether a consistent relationship existed between households and population in the Rochester area. The Department compared historical household growth in Olmsted County, on an annual percentage basis, to the average annual customer count growth during the forecast period used by MERC.[111]

92. The Department estimated the average annual household growth in the Rochester area after 1990 to be approximately 1.65 percent, but noted that there has been a downward trend in the rate of household growth over this period.[112]

93. The Department also concluded that average household size has remained relatively constant at approximately 2.5 individuals per household since 1970.[113]

94. According to Department witness Mr. Heinen, this conclusion confirmed that it was reasonable for MERC to compare the Rochester-Olmsted Council of Governments' population growth estimates to the Company's residential customer count forecast.[114]

95. The Department found that the average residential growth rate from MERC's forecast was comparable to household growth in the 1990s for the Rochester area but noticeably higher than household growth over the past 10 years.[115] The Company's residential customer count forecast compared to historical household growth is illustrated in the graph below.[116]

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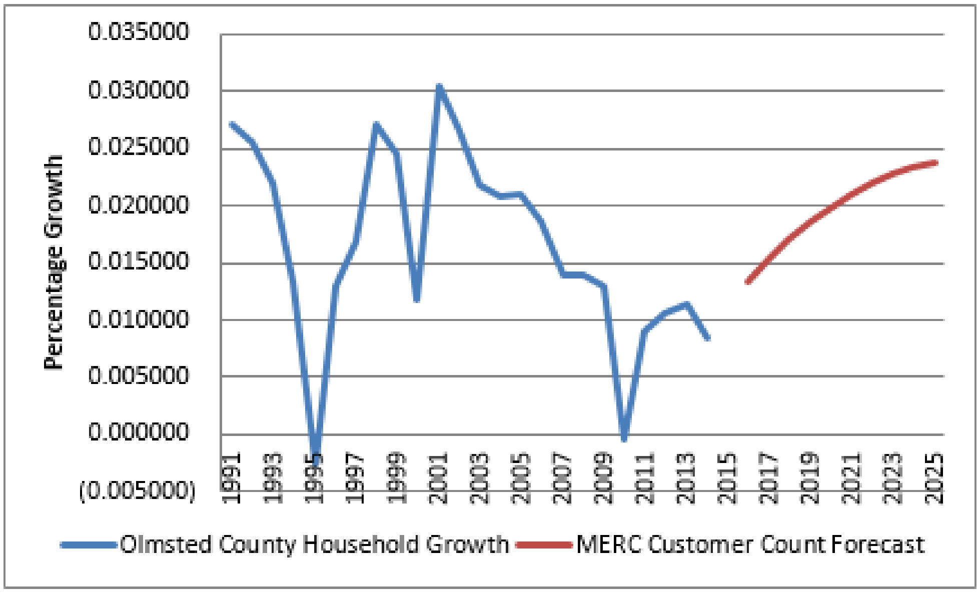
[109] Ex. 405 at 16 (Heinen Direct).
[110] *Id.* at 16, AJH-11.
[111] *Id.* at 16-17.
[112] *Id.* at 17, AJH-11.
[113] *Id.* at 10, AJH-18.
[114] *Id.* at 18.
[115] *Id.,* AJH-11.
[116] *Id.* at 18.

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



96. Based on this analysis, the Department stated that the Company's residential customer count projection assumed significant increases in population and household growth, above current conditions.[117] In the Department's view, this analysis showed that, if the DMC did not come to fruition or was implemented slower or in a manner different than MERC envisioned, MERC customer growth for the region likely would be lower than MERC had forecasted.[118]

97. In response to the Department's concerns, MERC stated that its forecasted growth rate is not that unusual considering the potential impact of a unique event like the expansion of the Mayo Clinic and the DMC initiative.[119] MERC also stated that an additional factor that could influence the forecast is the Rochester Public Utilities' (RPU's) intent to construct a new gas-fired generator in Rochester, impacting the need for additional gas capacity in the Rochester area.[120]

b. The Use of the Growth Rate from the Sales Forecast as the Growth Factor for the Design Day

98. The Department's second area of potential concern was MERC's decision to use the growth rate from its sales forecast as the growth factor in its Design Day estimate of peak demand.[121] As discussed above, MERC assumed that its Design Day would grow at the same rate as its estimated sales growth, 1.5 percent per year.

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117 Ex. 405 at 18 (Heinen Direct).
118 *Id.* at 19-20.
119 Ex. 10 at 6 (Clabots Rebuttal).
120 *Id.*
121 Ex. 405 at 20-21 (Heinen Direct).

99. The Department noted that MERC failed to provide any discussion of why it believed the two growth rates would be the same.[122]

100. The Department's witness Adam Heinen examined past regulatory filings to confirm whether the Company's assumed 1.5 percent Design Day growth assumption was reasonable. His analysis was complicated by the consolidation of MERC PGAs in July 2013, but he nevertheless reviewed historical MERC Design Day filings to validate the Company's growth assumption.[123]

101. After review of the 2015 and 2012 demand entitlement filings, Mr. Heinen stated that it was unclear if MERC's 1.5 percent growth rate was reasonable. He noted these filings show some variability in recent years. Based on the recent growth trends, Mr. Heinen concluded that a growth rate figure closer to 1.0 percent was more appropriate.[124]

c. MERC's 2015/2016 Design Day Capacity Amount

102. In addition to examining the Design Day growth rate, the Department examined the base peak amount (the 2015/2016 Design Day) used by MERC.[125]

103. The Department noted that MERC produced a different peak demand forecast in its annual demand entitlement filing submitted in a different PUC docket. Although the Company did not conduct a long-range peak demand forecast in its annual demand entitlement filing, the peak demand analysis it conducted in the demand entitlement filing was analogous to the base forecast MERC estimated in this docket. Both analyses had forecasts for the Rochester area.[126]

104. The presence of two peak demand forecasts led the Department to examine which forecast was most appropriate for determining need in this proceeding.[127]

105. The Department noted that the forecast in the demand entitlement filing was approximately 16,800 Dkt/day greater than the Company's projected peak demand forecast in this docket.[128]

106. Because the estimated base peak demand in the 2015 demand entitlement filing was greater than the base forecast in this proceeding, the Department concluded it has no concern that the base peak demand in this case is too large.[129]

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[122] *Id.* at 21.
[123] *Id.* at 22, AJH-12.
[124] *Id*. These filings also show an average increase in the Design Day requirement of 1.33 percent per year over the period 2006-2007 to 2015-2016. *Id*.
[125] Ex. 405 at 23-25 (Heinen Direct); Ex. 12 at 11, 21 (Mead Direct) (discussing 2015/2016 Design Day amount).
[126] Ex. 405 at 23 (Heinen Direct).
[127] *Id.* at 23, AJH-6.
[128] *Id.* at 24, AJH-6, AJH-7.
[129] *Id.* at 24.

107. Nonetheless, the Department conducted its own analysis to independently verify MERC's base peak demand. The Department used OLS regression to conduct a peak demand analysis using data over the period from January 2007 to February 2015. The Department's analysis was based, in part, on the maximum daily adjusted heating degree day for each month to estimate maximum daily peak load, on a monthly basis, for all of the TBSs in the Rochester area. The results of the regression analysis were then used to estimate peak load on a peak day, and adjusted to remove non-firm usage.[130]

108. The Department's analysis resulted in a base peak consumption amount that the Department concluded is comparable to the estimate filed by the Company in this docket.[131]

109. According to the Department, the results of its independent analysis confirm that the base peak consumption used by MERC for purposes of establishing the need for the Project was not unreasonable.[132]

110. In response to the Department's testimony, MERC explained that it uses the two peak day forecasts for different purposes with different results: one short-term forecast for MERC's annual demand entitlement filing and one long-term forecast prepared to support MERC's Rochester Project. One forecast looks out one year and the other spans many years. According to MERC, there was no issue with having two forecasts given that the two forecasts have different timelines.[133]

d. Department's Alternative Need Forecast

111. Because of its concerns regarding the accuracy of MERC's forecast, the Department conducted an alternative need forecast.[134] The Department's forecast included its own alternative customer count forecast.[135]

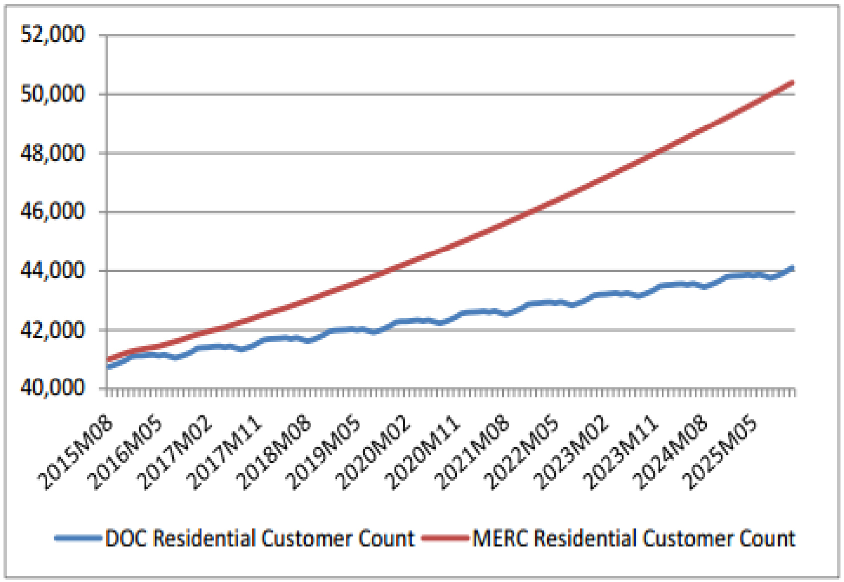
112. In conducting the alternative customer count forecast, Department witness Mr. Heinen used an OLS regression analysis as the basis for forecasting firm customer counts in the Rochester area. The analysis used monthly factors over the period from January 2007 to July 2015 and autoregressive terms to forecast Rochester area customer counts from August 2015 through December 2025.[136]

113. The Department's forecast results suggested an increase in retail customer counts of approximately 0.75 percent per year during the forecasting period. According to the Department, its customer count forecast is approximately 1.14 percent less than

[130] *Id.* at 24-25, AJH-13.
[131] *Id.* at 25, AJH-13.
[132] *Id.* at 25.
[133] Ex. 10 at 7 (Clabots Rebuttal).
[134] Ex. 405 at 25 (Heinen Direct).
[135] *Id.* at 25, AJH-14.
[136] *Id.*

the Company's projections of 1.89 percent. The difference between the two forecasts was illustrated in Graph 4 in Mr. Heinen's Direct Testimony and is displayed below:[137]

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



114. The results of the Department's and MERC's customer count forecasts differed because the Department's forecast was based solely on historical MERC operations and included a single autoregressive term, while MERC's forecast included several different autoregressive terms and a trend factor. Because the Company's trend factor had a positive value, it is likely that the trend factor put upward pressure on customer count growth.[138]

115. The Department's customer counts did not factor in the DMC as a potential growth factor. The Department did not account for the DMC because, according to the Department, it remains unclear when, or to what level, the DMC or other developments may impact future growth in the Rochester area.[139]

116. While the Department projected slower customer growth than did MERC, the Department concluded that a comparison of the customer count forecasts of the Department and MERC show that each are potentially acceptable. According to the Department's witness Adam Heinen, if the DMC is implemented as planned or there is a greater need for natural gas to produce electricity, then MERC's growth forecast is more likely to occur. Conversely, if the DMC is delayed or does not materialize and there is no greater need for natural gas to produce electricity, the Department's customer growth forecast is more likely to occur. The Department concluded that its forecast is a "status

[137] *Id.* at 27.
[138] Ex. 405 at 27 (Heinen Direct).
[139] *Id.* at 28, AJH-11.

quo" forecast or a lower-bound projection, while MERC's projected growth represents an optimistic or upper-bound forecast.[140]

117. This conclusion is supported by the fact that the Rochester-Olmsted Council of Governments anticipates future population growth in Olmsted County of between 1.00 percent and 1.50 percent on an annual basis.[141]

118. Because the Department viewed its results as representing the lower bound for reasonable growth, the Department used its customer count forecast results and applied those to the Company's use-per-customer results to estimate future sales. The Department then used these results to estimate firm demand growth over the forecast period.[142]

119. The Department also looked at recent demand entitlement filings for the MERC-NNG and MERC-Northern PGA, and determined that recent trends in Design Day growth have been approximately 1.0 percent.[143] In forecasting future reserve margins, the Department used the 1.0 percent growth rate for the Design Day.[144]

120. In response, MERC agreed that the Department's forecast, based strictly on historical data and using no forward-looking information, would be considered a "status quo" forecast or the low end of a range of possible growth outcomes.[145]

121. MERC disagreed that the Company's forecast is necessarily the high bookend of the range of possibilities but accepted that MERC's assumptions underlying its forecast were more optimistic.[146]

2. The OAG's Critique of MERC's Forecast and Design Day

122. The OAG noted that MERC relies on its forecast to justify the size of the Project, making the forecast an important factor in determining the need and reasonableness of the Project.[147]

123. The OAG's witness, Dr. Julie Urban, reviewed MERC's forecast.[148]

124. Based on Dr. Urban's review, the OAG raised several issues with MERC's forecasting methodology. The OAG asserted that: 1) MERC's growth rate is not supported by the historical data that is available; 2) MERC's customer count model is not

[140] *Id.* at 28.
[141] *Id.* at 28-29.
[142] *Id.* at 29.
[143] *Id.* at 29-30.
[144] *Id.* at 30.
[145] Ex. 10 at 4 (Clabots Rebuttal).
[146] *Id.*
[147] OAG Initial Br. at 19 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
[148] Ex. 300 at 1, 27-34 (Urban Corrected and Amended Direct). Dr. Urban is a Utilities Economist with the OAG, and has a Ph.D. in Economics. She has worked as an economist on utility matters for a number of years. *Id.* at 1-2.

reasonable; 3) MERC unreasonably assumed that Residential use-per-customer would remain constant for the entire time period; 4) MERC used *a priori* information to create its forecast; 5) MERC assumed that it is reasonable to apply an estimate of sales growth to its Design Day, which measures peak demand. The OAG maintained that these issues caused MERC to overestimate the growth in peak demand.[149]

a. Historical Sales Growth

125. With regard to the historical growth rate, the OAG noted that MERC forecasts that its firm peak demand will grow 1.5 percent per year from 2015 to 2042, but the average annual growth in sales from 2007 to 2015 was only 0.46 percent per year.[150] The following table sets forth the weather normalized sales data for the Rochester area from 2007 to 2015.[151]

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	32,287,597	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%

126. The OAG asserted that it is not reasonable for MERC to estimate that its demand will grow 1.5 percent per year when its average sales growth from 2007 to 2015 has been much less.[152]

127. The OAG also raised concerns about MERC doing a regression analysis for its forecast using only eight years of historical data, from 2007 to 2015. The OAG

[149] *See* Ex. 300 at 27-34 (Urban Amended and Corrected Direct); Ex. 307 at 4 (Urban Amended and Corrected Rebuttal); OAG Initial Br. at 19-20 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
[150] OAG Initial Br. at 20-21 (Oct. 11, 2016) (eDocket No. 201610-125583-01); Ex. 300 at 29-30 (Urban Amended and Corrected Direct).
[151] Ex. 300 at 29-30 (Urban Amended and Corrected Direct).
[152] Ex. 300 at 29-30 (Urban Amended and Corrected Direct).

recognized that MERC does not have reliable data prior to 2007, when MERC was purchased by Integrys, but was concerned about the changes in total sales from year to year. The OAG's witness, Dr. Urban, noted that available historical data shows substantial swings in total sales from year to year, even on a weather normalized basis. She asserted that there may be a problem with MERC's weather normalization methodology.[153]

128. MERC responded that it had stopped using data from before 2007 due to concerns the OAG raised in MERC's 2011 rate case with the quality of data from Aquila, MERC's predecessor. MERC asserted that using seven-and-one-half-years of historical data to prepare a ten-year forecast was adequate.[154]

129. MERC argued that the data constraints placed on the Company should not prevent MERC from seeking approval of an extension project, noting that waiting could create more serious capacity constraints and reliability concerns.[155]

130. With respect to the OAG's concern regarding MERC's weather normalization process, MERC explained that it used actual sales, not weather normalized sales, in its regression models and weather was used as an independent variable in the models to help explain the variation in sales in the Rochester area.[156]

131. In addition, MERC witness David Clabots explained that there are challenges associated with fully weather normalizing historical sales when the review period includes extreme weather situations. The year 2014 was exceptionally cold due to the Polar Vortex and 2015 was warm due to an El Niño weather event. During both of these extreme, opposing weather situations, weather normalization models tended to under-correct.[157]

132. Mr. Clabots also noted that trends in historical data need to be considered in context, even when viewed in a weather normalized basis. To provide further context, Mr. Clabots provided a table showing the average compound growth rate using weather normalized sales for the Rochester area.[158] The table is set forth below:

[153] *Id.* at 28-29.
[154] Ex. 10 at 12 (Clabots Rebuttal).
[155] *Id.*
[156] *Id.* at 13.
[157] Ex. 11 at 7 (Clabots Surrebuttal).
[158] *Id.* at 6-7.

MERC Rochester Pipeline Expansion Project

OAG- 155.5 Question 2

Rochester Weather Normalized Calendar Sales
Data Units: Therms

	Residential	SC&I	LC&I	Total	% Chg	Interruptible	Transport
2007	33,617,022	839,311	14,799,596	49,255,929		3,441,644	38,523,794
2008	34,431,489	880,932	15,106,799	50,419,220	2.36%	3,483,920	34,597,018
2009	35,410,050	1,016,451	15,112,268	51,538,769	2.22%	3,395,593	39,553,706
2010	33,655,403	1,060,105	14,473,411	49,188,919	-4.56%	2,923,720	39,746,885
2011	35,161,983	1,220,915	15,686,775	52,069,673	5.86%	2,827,514	38,590,434
2012	35,287,597	1,058,178	16,434,231	52,780,006	1.36%	1,900,678	42,095,612
2013	35,619,126	1,367,791	16,601,029	53,587,946	1.53%	2,685,061	38,172,017
2014	38,121,516	1,691,545	17,872,702	57,685,764	7.65%	1,835,438	43,832,113
2015	33,297,050	1,182,199	15,838,890	50,318,139	-12.77%	1,654,265	44,094,815

Average Compound Growth Rate 2007 - 2013 (ACGR)	**1.41%**
2007 - 2014 (ACGR)	**2.28%**
2007 - 2015 (ACGR)	**0.27%**

(1) Interruptible and Transport are not weather normalized.

(2) Recognize with the extreme weather in 2015 due to an El Nino event that the weather normalization model did not fully correct for weather and the total WN sales are understated to some degree.

Similarly due to the Polar Vortex, 2014 is overstated to some degree for for the same reason.

133. As this table shows, the average compound growth rate from 2007-2013 was 1.41 percent. The average compound growth rate for 2007-2014 went up to 2.28 percent, and then from 2007-2015, it fell to 0.27 percent.[159] According to Mr. Clabots, these differences in the average compound growth rates reflect in part the challenges associated with fully weather normalizing historical sales under extreme weather situations, such as the Polar Vortex of 2014 and the El Niño event in 2015.[160]

134. The Department also responded to the issues raised by Dr. Urban with regard to the historical data. The Department agreed with the OAG's observation that there is considerable fluctuation in the annual percentage change in firm demand since 2007, but noted that the fluctuation helps support the need for the Project. The Department stated that it is critical for MERC to be able to provide natural gas service during periods of fluctuation, such as the 2014 Polar Vortex.[161]

[159] Ex. 11 at 6 (Clabots Surrebuttal).
[160] Ex. 11 at 7 (Clabots Surrebuttal).
[161] Ex. 407 at 3 (Heinen Surrebuttal); Ex. 410 at 2 (Heinen Opening Statement).

b. MERC's Residential Customer Count

135. As discussed above, MERC's forecast used a monthly customer count model and a use-per-customer model to derive total expected sales by customer class.[162]

136. Like the Department, the OAG raised concerns about MERC's customer count model. The OAG agreed with the Department that MERC's estimate of a 2.0 percent per year increase in residential customers is not supported by historical data or population estimates from the Rochester-Olmsted Council of Governments. The OAG asserted that MERC's estimate of residential customer growth of 2.0 percent per year is overly optimistic, and instead supported the Department's forecast of customer count growth of 0.75 percent on an annual basis.[163]

c. MERC's Residential Use-Per-Customer Estimate

137. While the OAG agreed with the Department's concerns about customer count, the OAG also identified a concern relating to the use-per-customer included in the forecast of total sales. The OAG noted that both MERC and the Department assumed the residential use-per-customer would remain constant over time. The OAG asserted that this assumption was unreasonable because residential use has been trending downward due to a number of factors including increased efficiency in heating and cooling, and insulation improvements.[164]

138. One modification suggested by the OAG's witness, Dr. Urban, was inclusion of a time trend variable for the Residential class.[165] The OAG noted 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.[166] 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.[167]

139. The OAG noted that MERC used a time trend variable in its use-per-customer model for the Small C&I customer class, but not for the Residential class.[168]

140. The OAG asked MERC to include a time trend variable in the residential use-per-customer model.[169] When that step was taken, the average growth in total residential sales was lower. MERC estimated an average growth rate in residential sales

[162] Ex. 1 at 20 (Petition).
[163] Ex. 307 at 4-5 (Urban Amended and Corrected Rebuttal).
[164] Ex. 314 at 2 (Urban Opening Statement); OAG Initial Br. at 26-27 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
[165] Ex. 300 at 30 (Urban Amended and Corrected Direct).
[166] *See id.*
[167] *See* Tr. Vol. 1 at 193 (Urban).
[168] Ex. 300 at 30 (Urban Amended and Corrected Direct).
[169] *Id.;* Ex. 304, JAU-15 (Urban Direct Schedules).

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.[170]

141. To verify whether the time trend was a significant explanatory variable, the OAG asked MERC to calculate the p-value for the time trend coefficient.[171] The p-value measures the level of confidence as to whether an explanatory value is significant.[172] A p-value of zero indicates that the variable is "highly significant."[173] MERC's calculation showed the p-value for the time trend variable was 0.00 percent.[174]

142. According the OAG, the statistical significance of this trend coefficient verifies that the downward trend in use-per-customer should be taken into account when estimating residential sales.[175]

143. The OAG also asserted that if a time trend was taken into account, the growth in Design Day would be lower than the 1.0 percent estimated by the Department and lower than the 1.5 percent used by MERC.[176] As a result, the OAG asserted that MERC's assumption that residential use-per-customer will remain the same is unreasonable.

144. In response, MERC maintained that its residential use-per-customer model was statistically significant as submitted in the Petition, and therefore disagreed that a time trend variable is necessary for the residential class modeling.[177]

145. Further, the Company asserted that if a time trend variable were added, it would be inappropriate to add the variable in isolation, as requested by the OAG, without reviewing the entire model. MERC's witness David Clabots noted that the variables in the forecast model work together, such that the addition or modification of particular variables without corresponding adjustments to other variables in the model can yield inconsistent and unsound results.[178]

146. MERC also noted that although trend lines have their uses as visual aids, they are less reliable for purposes of forecasting outside the historical range of the data. Most time series do not behave as though there are straight lines. Rather, their levels and trends undergo evolution. For this reason, a linear trend model does not always produce a good forecast over the long term.[179]

[170] Ex. 10 at 14 (Clabots Rebuttal); Ex. 304, JAU-15 (Urban Direct Schedules) (showing Rochester Residential Forecast results using Rochester weather, with and without a time trend variable).
[171] Ex. 304, JAU-14 (Urban Direct Schedules).
[172] Ex. 307 at 6 (Urban Amended and Corrected Rebuttal); Tr. Vol. 1 at 19–20 (Urban).
[173] Ex. 307 at 6 (Urban Amended and Corrected Rebuttal); Ex. 10 at 14-15 (Clabots Rebuttal).
[174] Ex. 304, JAU-14 (Urban Direct Schedules).
[175] Ex. 307 at 6 (Urban Amended and Corrected Rebuttal).
[176] *Id.*
[177] Ex. 10 at 14 (Clabots Rebuttal).
[178] Ex. 11 at 13 (Clabots Surrebuttal); Ex. 26 at 2 (Clabots Opening Statement).
[179] Ex. 26 at 2 (Clabots Opening Statement).

147. MERC noted that a decreasing linear trend for residential customer usage is not realistic over the long-term as per-customer usage cannot decrease forever.[180] In MERC's view, forward-looking independent variables or *a priori* information are better suited for use in long-term forecasts.[181] Finally, MERC noted that to the extent a time trend variable were used, an economic trend variable, such as real personal income (RPI), would be more appropriate than the generic time trend variable suggested by the OAG.[182] MERC stated that RPI was highly significant with a p-value of 0.00 percent, using Rochester weather.[183]

148. In response to discovery, MERC included forecasts using RPI as a trend variable rather than a generic time trend variable.[184] Using RPI as a trend variable, MERC produced a forecast with a growth rate of 1.59 percent compared to 1.87 percent with no time trend variable, whereas the growth rate with the generic time trend was 1.34 percent. According to MERC, the RPI trend variable demonstrates that the impact of including a time trend variable is not as significant as the OAG suggested.[185]

d. Use of *A Priori* Information

149. The OAG also questioned MERC's use of *a priori* information in developing its sales forecast.[186]

150. The OAG's witness Dr. Urban raised concerns with MERC's selection of more robust models to incorporate the anticipated growth related to the Mayo Clinic expansion and its DMC project.[187]

151. Dr. Urban asserted that because the Rochester Residential and Small C&I customer count models are based on *a priori* information, the models are based not only on recent historical growth but on the expectations of future growth.[188]

152. In response, MERC clarified that it did not include an additional growth factor based on the DMC initiative in its forecast model. Instead, MERC considered the DMC initiative in its gauging the reasonableness of its forecasting model output.[189]

153. MERC's response did not resolve Dr. Urban's concerns. Dr. Urban asserted that MERC's use of *a priori* information to determine the reasonableness of its

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[180] *Id.* at 2-3; Tr. Vol. 1 at 185-185 (Urban) (acknowledging uncertainty regarding whether residential use per customer would continue to decline at the same rate forever).
[181] Ex. 26 at 2-3 (Clabots Opening Statement).
[182] Ex. 10 at 14 (Clabots Rebuttal).
[183] *Id.*
[184] Ex. 304, JAU-15 (Urban Direct Schedules) (MERC Response to OAG IR 155.7).
[185] Ex. 10 at 14 (Clabots Rebuttal).
[186] *Id.* at 15.
[187] Ex. 300 at 31-32 (Urban Amended and Corrected Direct).
[188] Ex. 300 at 31 (Urban Amended and Corrected Direct).
[189] Ex. 10 at 15 (Clabots Rebuttal).

forecast was not appropriate. Dr. Urban called the Mayo Clinic expansion speculative and maintained that the sales forecast of 1.5 percent average annual growth is too high.[190]

154. The OAG also asserted that MERC's overestimate of residential customer growth and use-per-customer means that MERC's proposal is likely to result in overbuilding of infrastructure and interstate pipeline capacity.[191]

155. MERC disagreed. According to MERC witness David Clabots, the use of *a priori* information in forecasting is not unusual. In Mr. Clabots opinion, using expert opinion or a forecaster's judgment when selecting variables or features of a model can be beneficial.[192]

156. MERC asserted that, given the unusual nature of the DMC initiative, it was reasonable to consider the Mayo Clinic's expansion plans and plans related to the DMC project in determining an appropriate forecast.[193]

e. Design Day Growth Rate

157. The OAG also asserted that MERC did not demonstrate it is reasonable for MERC to use its sales forecast growth rate as the growth rate for its Design Day. The OAG noted that MERC did not provide 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.[194]

158. The OAG stated that the record does not suggest any changes that could be made to correct this matter. The OAG recommended instead that the lack of evidentiary support for MERC's assumptions should go to the weight that MERC's forecast receives, and the reasonableness of relying on it to establish need.[195]

159. In light of the concerns discussed above, following submission of Rebuttal testimony, the OAG asked MERC to recreate its forecast with three changes: 1) use Rochester-specific weather data; 2) use the Department's customer count growth forecast; and 3) incorporate the time trend variable in the Residential use-per-customer model as discussed in the OAG's Direct Testimony.[196]

160. MERC had already incorporated Rochester weather-specific data in its sales forecast at the request of the Department.[197]

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[190] Ex. 311 at 1-2 (Urban Amended Surrebuttal).
[191] Ex. 307 at 6-7 (Urban Amended and Corrected Rebuttal).
[192] Ex. 10 at 15 (Clabots Rebuttal).
[193] *Id.*
[194] OAG Initial Br. at 31 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
[195] *Id.*
[196] Ex. 11, DWC-S2 (Clabots Surrebuttal).
[197] Ex. 9 at 7-8 (Clabots Direct).

161. Using the modifications specified by the OAG, without any further adjustments, resulted in a 10-year average total retail sales growth of negative 0.092 percent.[198]

162. When MERC provided the results to the OAG, MERC raised concerns about the modified forecast. MERC stated 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."[199]

163. MERC made the modifications specified by the OAG while also updating the forecast tables to include 2015 weather normalized actual sales (rather than forecasted 2015), which resulted in a 10-year average total retail sales growth rate of positive 1.1 percent.[200] MERC explained that it also ran the scenario with 2015 weather normalized sales to further demonstrate the significant impacts that changing forecast model variables in isolation can have.[201]

164. This one change in sales data swung the 10-year average growth rate from negative 0.092 percent to positive 1.1 percent; a fairly significant change that followed from only changing one data point. MERC contended that this swing further illustrates the challenges that can occur when an isolated data point or several variables are changed in isolation without reviewing the entire model. MERC noted that forecasting is much more than simply plugging numbers blindly into a model or growth-rate tables. It is a complex process with many inputs and variables and must be based on the overall information available at a specified time.[202]

165. For these reasons, MERC contended that the results of the OAG's hypothetical forecast are problematic. MERC continued to conclude that the Company's forecast, as filed, is reasonable, reflects overall growth projected in the Rochester area, and is the best evidence in the record of a reasonable forecast.[203]

166. The OAG continued to disagree. Based on the concerns discussed above, the OAG maintained that MERC's forecast overestimates the growth in peak demand for Rochester area customers. In the OAG's view, MERC's forecast model is flawed and MERC's decision to select the size of the Rochester Project based exclusively on its forecast is unreasonable.[204]

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[198] Ex. 11 at 13, DWC-S2 (Clabots Surrebuttal); Ex. 311 at 3 (Urban Amended Surrebuttal).
[199] Ex. 11 at 13-14 (Clabots Surrebuttal).
[200] *Id.* at 13, DWC-S2.
[201] *Id.* at 13.
[202] *Id.* at 13-14.
[203] *Id.* at 14.
[204] Ex. 311 at 24 (Urban Amended Surrebuttal).

3. Conclusions Regarding MERC's Forecast of its Future Capacity Needs

167. All parties agree that MERC has an immediate need for added capacity to meet existing peak demand in the Rochester area.[205] The parties do not agree on how much capacity will be needed to meet peak demand for firm customers in the future.

168. To estimate future capacity needs, it is necessary to estimate future growth in peak demand as measured by the Design Day.[206]

169. In similar types of proceedings where long term forecasts are used to make infrastructure decisions such as in Integrated Resource Plans or Certificate of Need filings, the forecast or need analysis typically includes: low growth, base growth, and high growth scenarios.[207]

170. In this case, the Administrative Law Judge concludes that the record supports the Department's estimate of 1.0 percent as a base growth projection in Design Day growth and MERC's forecast of 1.5 percent as a high-growth projection in Design Day growth.[208] The OAG's projection that sales growth will be negative 0.092 percent is not reasonable for use as a low-growth estimate of future Design Day growth.[209]

171. The Department's estimated Design Day growth rate of 1.0 percent is a reasonable base case scenario because it is based on actual Design Day data as well as the Department's sales forecast.[210] The Design Day data shows MERC's Design Day for the NNG PGA area has grown 1.33 percent on average from 2006/2007 to 2015/2016.[211] In addition, the Department estimated firm retail sales growth to be approximately 0.77 percent based on historical information.[212] Together these data points support the Department's estimate that a 1.0 percent growth rate in peak demand is a reasonable estimate of the status quo. Because the Department's estimate does not take into account any additional growth that may result from the DMC initiative, it is properly considered a base growth projection.

172. MERC's estimated growth rate of 1.5 percent is a reasonable high-growth projection, considering the additional growth that may result from the DMC plan. First, as noted above, the Design Day growth on MERC's system has been, on average, 1.33 percent.[213] The 1.33 percent average growth rate in the Design Day does not account for

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[205] Ex. 12 at 21, Table 1 (Mead Direct); Ex. 405 at 58 (Heinen Direct); Ex. 300 at 34-35 (Urban Amended and Correct Direct).
[206] Tr. Vol. 1 at 24 (Lee); *see also* Ex. 405 at 8-9 (Heinen Direct).
[207] Ex. 407 at 6 (Heinen Direct).
[208] *See* Ex. 405 at 29-30 (Heinen Direct); Ex. 12 at 21 (Mead Direct).
[209] Ex. 311 at 3 (Urban Amended Surrebuttal).
[210] Ex. 405 at 25-30, AJH-12 (Heinen Direct).
[211] *Id.*, AJH-12, at 2 of 2.
[212] *Id.* at 26-29.
[213] Ex. 405, AJH-12, at 2 of 2 (Heinen Direct).

additional peak demand growth that will likely be caused by the Mayo Clinic expansion under the DMC plan and related economic growth in the Rochester area.

173. Second, there is evidence that the DMC initiative is likely to result in additional growth in peak demand. As of April 1, 2016, about $150 million of private funds had already been invested in the DMC plan.[214] In addition, the Rochester-Olmsted Council of Governments is projecting an annual increase in the population of Olmsted County of approximately 1.50 percent from 2010-2020, 1.52 percent from 2020-2030, and 1.01 percent from 2030-2040.[215] Consideration of this *a priori* information is appropriate given the unusual nature of the DMC plan and the legislative backing of the plan.[216]

174. Third, historical sales data support MERC's forecast of Design Day growth of 1.5 percent as an upper-bound projection. MERC's weather normalized sales data show that the average compound growth rate in firm sales in the Rochester area was 1.41 percent per year from 2007-2013.[217] This historic sales growth rate is close to MERC's projected forecast Design Day growth rate of 1.5 percent, and does not take into account any additional growth from the DMC initiative.

175. The record also reflects that the average compound growth rate for sales from 2007-2014 was significantly higher, 2.28 percent, but fell to 0.27 percent for 2007-2015. The OAG focuses on the average growth rate from 2007-2015 to argue that MERC's forecast is too high, but fails to recognize that the unusually low number is likely caused in part by the El Niño effects in 2015.[218] As explained by MERC witness, David Clabots, these differences in the average compound growth rates for 2007-2013, 2007-2014, and 2007-2015 reflect, at least in part, the challenges associated with fully weather normalizing historical sales under extreme weather situations.[219] In addition, the swings in the data support MERC's projected growth rate of 1.5 percent rather than a lower rate as suggested by the OAG. MERC must be able to meet the actual demand on the coldest day, not the average demand over time.

176. For these reasons, the Administrative Law Judge concludes that the record supports MERC's estimate of 1.5 percent growth in the Design Day as a high-growth estimate for planning purposes.

177. The record does not support use of the negative 0.092 percent growth rate presented in the OAG's testimony.[220] The Administrative Law Judge concludes that this estimate is not reasonable for purposes of projecting MERC's future need for several reasons. First, as noted above, MERC's Design Day in its NNG PGA area has grown an average of 1.33 percent per year from 2006/2007 to 2015/2016.[221] In addition, the

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[214] Ex. 5 at 37, ASL-2 (Lee Direct); *see also* Minn. Stat. § 469.47.
[215] Ex. 9, DWC-2 (Clabots Direct).
[216] Minn. Stat. §§ 469.40-.47.
[217] Ex. 11 at 6 (Clabots Surrebuttal).
[218] *Id.* at 7.
[219] *Id.* at 6-7.
[220] Ex. 311 at 3 (Urban Surrebuttal).
[221] Ex. 405, AJH-12 at 2 of 2 (Heinen Direct).

evidence in the record suggests that the DMC plan will lead to substantial growth in the Rochester area. Finally, as noted by MERC's expert, "[c]hanging variables in isolation, …, risks inconsistent and potentially skewed results."[222] In fact, when MERC used the OAG's assumptions and updated the forecast tables to include 2015 weather normalized actual sales rather than forecasted 2015 sales, the average retail sales growth rate was positive 1.1 percent as opposed to negative 0.092 percent.[223]

178. For these reasons, the forecast of negative 0.092 percent growth in sales is not reasonable for use in estimating growth in Design Day. It is critical that MERC have sufficient capacity to meet peak demand of firm customers on extremely cold days. In the view of the Administrative Law Judge, use of a negative 0.092 growth rate to estimate future Design Day growth would place MERC's customers at real risk of not having sufficient capacity if Design Day conditions occur.[224]

179. In summary, the Administrative Law Judge concludes that MERC's estimate that the Design Day will grow by 1.5 percent per year is a reasonable upper-bound estimate of its forecasted need, and the Department's estimate that the Design Day will grow by 1.0 percent per year is a reasonable lower-bound estimate of MERC's forecasted need.

B. Reasonableness of MERC's RFP Process

1. Overview of MERC's RFP Process

180. Based on its forecast, MERC evaluated how to meet its current and future Design Day needs.[225]

181. MERC currently has a contract with NNG for NNG to provide approximately 55,000 Dth/day of capacity to the Rochester area.[226] There are no other pipelines that provide capacity to this area.[227] Any competing pipeline would need to build at least 80 miles of pipeline, requiring a major capital expenditure that would be amoritized over the investment. As a result of these economic disincentives, MERC has effectively been a captive customer of NNG.[228]

[222] Ex. 11 at 13 (Clabots Surrebuttal).
[223] *Id.*
[224] While the Administrative Law Judge does not recommend use of the OAG's growth rate, the Administrative Law Judge does agree with the OAG that MERC should have provided a more detailed explanation as to why it included a time trend variable for the Small C&I class but not for the Residential class. *See* Ex. 300 at 30 (Urban Amended and Corrected Direct); OAG Initial Br. at 24 (Oct. 11, 2016) (eDocket No. 201610-125583-01). MERC maintains that its sales forecast was statistically significant without the variable, but fails to explain the basis for this assertion. Ex. 10 at 14 (Clabots Rebuttal). The Administrative Law Judge recommends that in future filings of this type, MERC include a detailed explanation as to why a time trend variable is or is not used for each class of firm customers.
[225] Ex. 1 at 2, 19-28 (Petition); Ex. 5 at 6-11, 21-25 (Mead Direct).
[226] Ex. 12 at 11 (Mead Direct).
[227] Ex. 12 at 17-18 (Mead Direct).
[228] Ex. 12 at 22 (Mead Direct); Ex. 19 at 5 (Sexton Rebuttal).

182. Rather than simply negotiate a contract for additional capacity with NNG, MERC issued a competitive RFP to meet its future Design Day requirements.[229] To determine the amount of capacity requested by the RFP, MERC started with its forecasted Design Day needs for the winter of 2042/2043, approximately 91,000 Dth/day.[230] MERC added a five percent reserve margin to its forecast of about 91,000 Dth/day, which converts the capacity requirement to about 96,000 Dth/day. MERC rounded this number up to 100,000 Dth/day for use in its RFP.[231]

183. The RFP requested that bidders provide incremental firm transportation capacity to MERC at Rochester, Minnesota, with a term commencing August 1, 2017, and with rates quoted based on a 25-year contract term. The RFP also requested that respondents provide this capacity under one of two delivery quantity scenarios. The first scenario requested that bidders develop a new pipeline that would provide 100,000 Dth/day of firm transportation capacity to a new MERC TBS on the northwest side of Rochester. The second scenario requested that bidders work with NNG to provide an incremental 45,000 Dth/day of firm transportation capacity to Rochester at the existing Rochester gate stations.[232]

184. MERC requested a 2017 in-service date because, at the time the RFP was developed, MERC's existing firm capacity rights with NNG of 55,169 Dth/day to Rochester had a contract termination date of October 31, 2017. The expiration provided MERC with the opportunity to request competitive bids to support both the future projected growth requirements and the existing demand in the Rochester area.[233] As such, if a new bidder provided the lowest cost delivery, then the new bidder could displace the existing 55,169 Dth/day of existing NNG capacity to Rochester as well as provide the incremental 45,000 Dth/day of capacity designed to meet MERC's projected 25-year growth requirements.[234] Alternatively, under the second scenario, MERC could extend the existing capacity agreement with NNG and add an additional 45,000 Dth/day of firm capacity to support long term growth.[235]

185. MERC issued its RFP on January 5, 2015 to five active pipeline companies operating in the general vicinity of Rochester, Minnesota.[236] In addition, MERC published the RFP on its website to solicit additional responses.[237]

186. On January 16, 2015, three companies responded to the RFP: NNG, Northern Border Pipeline Co. (NBPL), and Twin Eagle.[238] NNG responded with multiple variations for expanding its interstate pipeline system. NBPL proposed to build a new 80-

[229] Ex. 17 at 38 (Sexton Direct).
[230] Ex. 12 at 21 (Mead Direct) (Table 1, Rochester Design Day column); Ex. 17 ay 40 (Sexton Direct). The actual projection for 2042/2043 using a 1.5 percent growth rate is 91,075 Dth/Day.
[231] Ex. 17 at 40 (Sexton Direct).
[232] *Id.* at 39.
[233] *Id.* at 40.
[234] *Id.*
[235] *Id.*
[236] Ex. 17 at 38-39 (Sexton Direct); Ex. 12 at 9 (Mead Direct).
[237] Ex. 17 at 39 (Sexton Direct). Ex. 12 at 9 (Mead Direct).
[238] Ex. 17 at 41 (Sexton Direct).

mile pipeline to serve the Rochester area. Twin Eagle also proposed to build a new pipeline.[239]

187. The three bidders submitted updated proposals on February 18 and 19, 2015 after discussing the initial proposals with MERC. Specifically, Twin Eagle submitted two proposals, NBPL provided one proposal, and NNG submitted multiple proposals.[240]

188. With respect to NNG's proposals, NNG provided one proposal (Proposal 3.0) that complied with the terms requested in the RFP. NNG also provided several additional proposals that MERC determined deviated from the parameters of the RFP, but which provided alternatives for MERC to consider.[241]

189. NNG's Proposal 3.0 was substantially less expensive than the alternatives proposed by Twin Eagle and NBPL. NNG's proposal was at least $50 million less (on a net present value basis) than any of the proposals offered by Twin Eagle and NBPL.[242]

190. Based on its review of the proposals, MERC decided to negotiate a contract with NNG because NNG's proposal had the lowest capital costs, least amount of construction, shortest construction time to be in service, and allowed the most hourly flexibility.[243]

191. MERC did not enter into a contract for Proposal 3.0 as initially offered. Instead, MERC entered into negotiations with NNG to enhance Proposal 3.0.[244]

192. As a result of the negotiations, NNG agreed to provide an addition 10,500 Dth/day in 2018 and the remaining 34,500 Dth/day in 2019, for a total of 45,000 additional Dth/day by plan year 2019/2020.[245] MERC was also able to negotiate a number of additions and changes to the base proposal provided in response to the RFP.[246] Those changes include: fixed rates associated with the extension of existing firm delivery entitlement to the Rochester market; firm growth capacity rights to other MERC markets served by NNG in southeastern Minnesota at NNG's tariff rate; ability to use up to 20 percent of the Rochester entitlement to deliver to markets other than Rochester at fixed rates; additional growth volume up to 2,000 Dth/day during any odd-numbered year of the agreement; and five year extension rights at fixed rates at the end of the 25-year contract term.[247]

[239] Ex. 12 at 10 (Mead Direct); Ex. 306, Schedule JAU-5 (Urban Direct Schedules).
[240] Ex. 17 at 41 (Sexton Direct).
[241] *Id.* at 41-42.
[242] *Id.* at 45.
[243] Ex. 27 at 2 (Mead Opening Statement).
[244] Ex. 17 at 45 (Sexton Direct).
[245] *See* Ex. 12 at 21 (Mead Direct); Ex. 17 at 45 (Sexton Direct).
[246] Ex. 17 at 46-47 (Sexton Direct).
[247] Ex. 17 at 46-47 (Sexton Direct).

193. The terms of the contract negotiated between MERC and NNG are included in a 25-year Precedent Agreement (PA), which was finalized in October 2015.[248]

194. In January 2016, MERC hired an independent consultant, Timothy Sexton, to evaluate MERC's RFP process, the selection of NNG, and the final terms of the PA.[249] MERC did not share with Mr. Sexton the Company's internal evaluation of the different bid responses prior to Mr. Sexton completing his evaluation.[250] Instead, Mr. Sexton did his own analysis, including his own cost analysis.[251]

195. Based on his review, Mr. Sexton concluded that MERC's RFP process was an effective method for obtaining bids from multiple pipeline companies. Mr. Sexton further concluded that MERC properly evaluated the proposals that were received through the RFP process.[252]

196. Mr. Sexton's analysis also confirmed that NNG's Proposal 3.0 was the lowest cost alternative of the bids that were responsive to the RFP. In doing his evaluation, Mr. Sexton compared the long-term costs of the responsive proposals from NNG, NBPL, and Twin Eagle over the 25-year contract term.[253]

197. Mr. Sexton also compared the cost of the PA to the responsive proposals. Mr. Sexton determined that the cost of the PA is less than NNG's Proposal 3.0, the NBPL Proposal, and the Twin Eagle Proposals.[254]

198. Finally, Mr. Sexton concluded that the RFP process allowed MERC to "exert considerable leverage to obtain more favorable terms from NNG."[255]

2. The Department's Review of MERC's RFP Process

199. The Department evaluated MERC's RFP process to assess whether the RFP was inclusive of all potential responding parties and whether the participating parties had the benefit of a fair process. The Department also reviewed the results of the RFP to determine whether MERC had selected the lowest cost option and had ensured there were reasonable provisions in the resulting contract to protect ratepayers.[256]

200. Department witness Michael Ryan conducted the Department's analysis.[257]

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[248] *Id.*; Ex. 12 at 10-11 (Mead Direct).
[249] Ex. 27 at 2 (Mead Opening Statement); Tr. Vol 1 at 155 (Sexton). Mr. Sexton is a licensed professional engineer and has worked in the gas industry for approximately 27 years. Ex. 17 at 1-3 (Sexton Direct).
[250] Ex. 28 at 1 (Sexton Opening Statement).
[251] Ex. 17 at 44-45 (Sexton Direct).
[252] *Id.* at 38-43, 52; Ex. 19 at 2 (Sexton Rebuttal).
[253] Ex. 17 at 44-45 (Sexton Direct); Ex. 18 (Sexton Direct Exhibit 3).
[254] Ex. 17 at 51-52 (Sexton Direct).
[255] Ex. 19 at 5 (Sexton Rebuttal).
[256] Ex. 402 at 6 (Ryan Direct).
[257] *Id.* at 1-15. Mr. Ryan has significant experience regarding the issuance and evaluation of RFPs for natural gas capacity. *Id.* at 1.

201. In reviewing whether MERC's RFP process was inclusive of all potential parties, Mr. Ryan identified only one potential bidder, Alliance, not directly solicited by MERC.[258] The Alliance pipeline travels through southern Minnesota near the Rochester area.[259] MERC decided not to send the RFP to Alliance because Alliance is a wet pipeline. In order for MERC to obtain supply from a wet pipeline, a processing plant would be needed at the interconnection between Alliance's pipeline and MERC's distribution system, to extract hydrocarbon liquids and allow the "dry" natural gas to flow into Rochester. According to MERC, the additional construction to complete the conversion would be cost-prohibitive and impractical.[260] In addition, MERC noted that a consultant for Alliance did make an inquiry to MERC based on the RFP, but no bid was received.[261]

202. Based on these facts, the Department maintained that MERC should have specifically included Alliance in the RFP and designed the RFP to request proposals for delivery of "dry" gas. Such an approach would have allowed for confirmation that use of the Alliance pipeline was cost-prohibitive. Nonetheless, because Alliance was aware of the RFP but did not submit a bid, the Department concluded that MERC had reasonably addressed the issue of whether its RFP had been appropriately inclusive of possible bidders.[262]

203. The Department also reviewed the RFP and found that the RFP documents were sufficiently detailed. The Department concluded that the RFP was structured to allow for full project comparison between the incumbent pipeline company, NNG, and the other bidders.[263] In addition, the Department noted that the RFP requested responses two weeks after the date of issuance, which the Department found to be a sufficient amount of time. Mr. Ryan noted that industry practice varies considerably depending on the level of complexity and other factors, but the two-week timeframe would allow responses or, at a minimum, indications of intent from potential parties.[264]

204. The Department reviewed the RFP responses, as well as a spreadsheet that MERC prepared, for its internal review of the responses.[265] MERC's spreadsheet was a high-level summary of the pricing provided by suppliers along with other non-quantitative aspects that were factored into the Company's decision. All categories were weighted, with project cost holding the majority of the weight.[266]

205. The Department concluded that the weights MERC assigned in its spreadsheet of the RFP results were reasonable, and that the information and weights to each category appeared reasonable. Overall, the driving component was cost.[267]

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[258] Ex. 402 at 7 (Ryan Direct).
[259] *Id.* at 7.
[260] *Id.* (citing MERC Response to DOC IR No. 44).
[261] *Id.*
[262] *Id.* at 7-8.
[263] *Id.* at 8.
[264] *Id.*
[265] Ex. 402 at 9-10 (Ryan Direct); *see also* Ex. 403, MR-1 (Ryan Direct Attachment).
[266] Ex. 402 at 10 (Ryan Direct).
[267] *Id.*

206. The Department also reviewed Mr. Sexton's analysis of the RFP process. The Department concluded that Mr. Sexton's assumptions and cost component calculations were accurate. The Department was also able to tie Mr. Sexton's statements to the responses provided by the bidding parties and confirm the calculations.[268]

207. The Department agreed that Mr. Sexton's analysis showed that NNG's response was the most competitive bid received through the RFP process.[269]

208. Based on its investigation, the Department concluded that MERC's RFP process was fair and reasonable. It provided a comprehensive survey of the market and the potential alternatives for interstate pipeline services to the Rochester TBSs. While other pipelines may have difficulty serving Rochester, the Department found that MERC made reasonable efforts to address this issue through the timing of the process and by allowing other bidders the opportunity to provide competitive bids on the Project.[270]

209. The Department also noted that, in addition to NNG providing the most cost competitive bid, the incumbent interstate pipeline company was able to differentiate itself by its ability to serve Rochester at multiple points and by capping the reservation price of NNG capacity. As a result, the reservation price will not increase if NNG files with the Federal Energy Regulatory Commission for increased tariff rates.[271]

3. The OAG's Review of MERC's RFP Process

210. The OAG also reviewed MERC's RFP process. Dr. Urban, the OAG's witness, raised several concerns with the RFP process. First, she noted that MERC designed its RFP based on a 25-year forecast of its Design Day needs in the Rochester area. The OAG argued that MERC should not have relied exclusively on its forecast in designing its RFP. In the OAG's view, use of MERC's forecast places a significant risk on ratepayers because the forecast may be too high. If this is the case, MERC will have obtained more capacity than is necessary.[272]

211. Second, the OAG asserted that, regardless of MERC's forecast, the Company should have solicited a range of alternatives, not just bids that provided 100,000 Dth/day of capacity. The OAG noted that even assuming MERC's forecast is accurate, the bulk of the capacity will not be needed for some time.[273] The OAG asserted that the Company should have sought bids for smaller capacity proposals, or phased proposals, which could have minimized the risk to ratepayers while providing short-, medium-, and long-term solutions.[274]

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[268] *Id.* at 11.
[269] *Id.* at 11-12.
[270] *Id.* at 14-15.
[271] *Id.* at 12.
[272] Ex. 300 at 45 (Urban Amended and Corrected Direct); Ex. 307 at 12 (Urban Amended and Corrected Rebuttal).
[273] Ex. 300 at 47 (Urban Amended and Corrected Direct).
[274] *Id.* at 46-47.

212. Third, the OAG asserted that MERC's analysis of the RFP bids was not sufficiently rigorous. In support of its position, the OAG pointed to a spreadsheet that MERC used to analyze the different bids it received. The OAG noted that the spreadsheet includes four responses to the RFP: Twin Eagles Route A, NBPL's Ventura, NNG Proposal 3.0, and NNG Proposal 4.2. The OAG pointed out that NNG provided a number of other proposals, and questioned why those proposals were not included in the spreadsheet.[275] In addition, the OAG maintained that MERC did not provide enough narrative detail about how it ranked the various proposals. Finally, the OAG stated that NNG Proposal 4.2 scored higher than NNG Proposal 3.0, and asserted that MERC should have selected that proposal over Proposal 3.0 for purposes of negotiating with NNG.[276]

213. In response, MERC asserted that by structuring the RFP to request 100,000 Dth/day of capacity, MERC was able to create a competitive environment. With this quantity in the solicitation, NNG was faced with a realistic risk that it could lose MERC's existing 55,169 Dth/day position in Rochester and other competing pipelines could provide all of MERC's Rochester requirements. According to MERC, selecting 100,000 Dth/day as the target capacity served two important goals: 1) ensuring sufficient capacity for MERC to serve customers in the Rochester area and elsewhere on the system for the long term; and 2) providing a sufficiently large capacity position to entice other pipelines to submit competing proposals.[277]

214. MERC noted that this approach was successful in that the Company received bids from three distinct service providers.[278]

215. According to MERC, if a smaller project was pursued the RFP would not have attracted bids from any companies other than the incumbent provider, NNG.[279] Construction of a new 80-mile pipeline would have made a smaller capacity contract cost-prohibitive for companies other than NNG.[280] As a result, if MERC had simply requested to meet near-term capacity requirements, competition would not have been fostered and MERC's negotiating power with NNG would have been significantly reduced.[281] By structuring the RFP to encourage bids from other providers, MERC was able to negotiate price terms and other terms that are more favorable than what NNG would likely offer in absence of this competitive pressure.[282]

216. The Department also addressed the OAG's concern that MERC's RFP process may not have been reasonable because the RFP requested only one size of project. According to Department witness Mr. Ryan, it is beneficial for entities issuing RFPs to provide specific parameters in the RFP to allow the bids to be compared on an

[275] Ex. 307 at 12 (Urban Amended and Corrected Rebuttal) (referring to Ex. 403, MR-1 (Ryan Direct Attachment)).
[276] *Id.* at 12-14.
[277] Ex. 19 at 7-8 (Sexton Rebuttal).
[278] *Id.*
[279] Ex. 13 at 9 (Mead Rebuttal).
[280] Ex. 19 at 7 (Sexton Rebuttal).
[281] Ex. 13 at 9 (Mead Rebuttal); Ex. 19 at 7-8 (Sexton Rebuttal).
[282] Ex. 19 at 7-8 (Sexton Rebuttal); Ex. 17 at 46-50 (Sexton Direct); *see also* Ex. 16 at 7, 9 (Mead Surrebuttal).

apples-to-apples basis. The method that MERC used allowed it to compare the three bids equally. If the MERC RFP had requested multiple sizes of proposals, as was suggested by the OAG, the Company would have received varying responses that would have been difficult to compare in a meaningful manner. Also, under the process used by MERC, if the RFP had needed to be adjusted with a different size after the initial solicitation, MERC could have issued an amended RFP with the new size preference.[283]

217. The Department also noted that the record shows that NNG provided the most competitive bid of the three companies that responded to the RFP. After NNG was determined to be the most competitive bidder, MERC continued to negotiate the terms of a contract with NNG. As a result, the OAG's concerns about MERC's analysis of the bids really relates to MERC's decision to use Proposal 3.0 as the starting point for negotiations instead of proposal 4.2, not MERC's selection of NNG.[284]

218. MERC asserted that the OAG's criticism regarding the selection of Proposal 3.0 instead of Proposal 4.2, as the starting point for negotiations, failed to consider that Proposal 4.2 was not a fixed priced proposal. Proposal 4.2 had two phases and the second phase would be based on actual costs incurred at the time of construction. According to MERC, an uncapped price for the second phase would expose customers to the risk of paying more in the long run and MERC would have had little leverage as it would have no other options other than to work with NNG.[285] MERC also identified operational issues with Proposal 4.2[286]

219. Finally, with regard to the analysis of the bids, MERC asserted that it did consider the relative costs and benefits of an incremental approach to expanding capacity in the Rochester area. MERC noted that a series of smaller projects would likely have been more expensive than the cost of the PA.[287]

4. Analysis of the RFP Process

220. The Administrative Law Judge finds that a preponderance of the evidence shows MERC's RFP process was fair and reasonable.

221. First, the record supports MERC's decision to determine the size of the capacity requested in its RFP based on its projected need over 25 years. By requesting bids for 100,000 Dth/day, the project was designed to meet MERC's forecasted Design Day needs to 2042 and was large enough to entice companies other than NNG to provide bids. The results show that the 100,000 Dth/day capacity size put pressure on NNG to provide a competitive bid.

222. If MERC had issued an RFP for more incremental capacity to meet only near-term demand requirements as suggested by the OAG, the quantity would not have

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[283] Ex. 404 at 2 (Ryan Surrebuttal).
[284] *Id.* at 2-3.
[285] Ex. 16 at 14 (Mead Surrebuttal).
[286] *Id.* at 17.
[287] *Id.* at 10-11.

been sufficient to make it economic for any company other than NNG to submit a bid given the significant barrier to entry created by the 80-mile pipeline construction requirement for new entrants.[288]

223. Second, the record supports MERC's decision to negotiate a contract with NNG. NNG's bid was the lowest priced.[289] Therefore, it was fair and reasonable for MERC to proceed with negotiations with NNG.

224. With regard to the OAG's concern that NNG should have picked NNG Proposal 4.2 rather than Proposal 3.0 for purposes of negotiating with NNG, the Administrative Law Judge believes this concern is misplaced. The reasonableness of Proposal 3.0 is not an issue in this case because MERC did not end up signing a contract for Proposal 3.0. Rather, it entered into the PA, which has different terms than Proposal 3.0. Thus, the real question is not whether Proposal 4.2 is a better option than Proposal 3.0, but whether the PA is a better option than Proposal 4.2 or some other option for meeting MERC's future Design Day needs.[290] That question is addressed in the next section.

225. Similarly, the OAG's suggestion that MERC should have issued an RFP for a smaller project (i.e. less than 45,000 Dth/day of new capacity) really raises the question of whether a smaller project is a better alternative than the PA. That issue is also addressed in the next section.

C. Reasonableness of the Rochester Project: PA and Phase II

1. Description of the PA

226. As discussed above, MERC negotiated a PA with NNG. The PA is for an initial term of 25 years, but can be canceled if not approved by the Commission.[291]

227. Under the PA, MERC is purchasing an additional 45,000 Dth/day of firm capacity on NNG's upgraded pipeline into the Rochester area. This means MERC is contracting for a total of 100,169 Dth/day.[292]

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[288] Ex. 19 at 5-6 (Sexton Rebuttal).
[289] Ex. 17 at 44-45 (Sexton Direct).
[290] Even if a comparison of Proposal 3.0 to Proposal 4.2 was relevant for purposes of evaluating the RFP process, MERC's decision to use Proposal 3.0 rather than Proposal 4.2 as the starting point for negotiations is reasonable because Proposal 4.2 is not a fixed price option. Rather, the second phase of Proposal 4.2 was to be at actual cost at the time. Thus, contrary to the OAG's suggestion, there is no certainty that Proposal 4.2 would have been lower cost than Proposal 3.0. *See* Ex. 306, JAU-5 at 31, 40 (Urban Direct Attachments); *see also* Ex. 16 at 14 (Mead Surrebuttal).
[291] Ex. 12 at 11 (Mead Direct); *see also* Ex. 306, JAU-7 (Urban Direct Schedules).
[292] Ex. 12 at 12 (Mead Direct).

228. Under the terms of the PA, MERC will be responsible to pay for the capacity provided pursuant to the PA. The amount is about $60 million, which is slightly higher than projected in the Petition.[293]

229. The PA allows MERC to cancel the contract if it does not receive appropriate regulatory approval from the Commission.[294]

230. As noted above, the PA includes a number of changes and enhancements from Proposal 3.0, which provide added certainty and flexibility for MERC. These provisions include:

- Fixed delivery rates for the existing Rochester entitlement: The rates are not subject to change when NNG's maximum tariff rates change. Instead, the existing Rochester entitlement would be fixed at the current maximum rate during the 25-year term of the agreement.[295] This provision will provide MERC and its customers with protection against increasing tariff rates with respect to its pre-existing firm delivery entitlement to Rochester during the term of the agreement. MERC views this provision as important because NNG has publicly stated in the past year that it intends to initiate a rate case in the next few years and its maximum tariff rates are likely to increase.[296]

- Firm growth capacity rights to other MERC markets: The negotiated agreement includes an additional 5,439 Dth/day of firm delivery to nine MERC delivery points commencing as of the Phase I start date (November 2018) and an additional 2,593 Dth/day of firm delivery to 21 MERC delivery points as of the Phase II start date (November 2019).[297] The firm capacity would be at NNG's maximum tariff rate.[298] According to MERC, the capacity being added to the 21 MERC TBSs would not be possible at this price without the Rochester Project.[299]

- Flexibility to use Rochester total firm entitlement to serve markets other than Rochester: MERC is allowed to direct up to 20 percent of the firm Rochester entitlement to alternate MERC delivery points within the MERC system in Minnesota at no additional charge.[300] Usually, when interstate pipelines develop discounted or negotiated rates for firm transportation service to a specific delivery location (such as a fixed rate to Rochester), the shipper is not entitled to

[293] Ex. 5 at 20 (Lee Direct).
[294] *Id.*
[295] Ex. 17 at 47-48 (Sexton Direct).
[296] *Id.*
[297] *Id.* at 48.
[298] *Id.*
[299] Ex. 12 at 10-11 (Mead Direct); *see* Ex. 17 at 48-49 (Sexton Direct).
[300] Ex. 12 at 11, 22 (Mead Direct); Ex. 17 at 49 (Sexton Direct).

utilize the negotiated or discounted rate capacity at alternate locations at the discounted or negotiated price.[301]

- Additional growth up to 2,000 Dth/day: The negotiated MERC and NNG agreement provides MERC the option to purchase up to 2,000 Dth/day of additional capacity during any odd-numbered year of the agreement. The capacity would be provided at a predetermined Capital Recovery Rate for NNG, and give MERC the flexibility to add incremental capacity if needed to meet any additional incremental demand needs during the term of the PA.[302]

- A one-time five-year extension right at fixed rates upon completion of the 25-year contract: The provision gives MERC the option to extend the contract at fixed discounted rates.[303]

231. Pursuant to the PA, NNG will build the additional capacity into the two transmission laterals that connect to MERC's TBS.[304] The PA calls for NNG to provide increased capacity into Rochester TBS 1B and TBS 1D, and to build a new TBS that will replace the existing TBS 1B.[305]

2. Size of the Project: Reserve Margins and Excess Capacity Costs

232. The following chart, prepared by MERC witness Sarah Mead, shows how and when the new capacity will be added to TBSs 1B and 1D and the new TBS. The chart also estimates the reserve margin for the Rochester area between 2015/2016 and 2039/2040 based on MERC's forecast of the Design Day and the addition of the new capacity.[306]

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	-9.50%	
2016/2017	61,842	36,707	18,462	0	55,169	-10.80%	
2017/2018	62,770	36,707	18,462	0	55,169	-12.10%	
2018/2019	63,712	47,207	18,462	0	65,669	3.10%	Phase I
2019/2020	64,667	40,707	18,462	41,000	100,169	54.90%	Phase II
2020/2021	65,637	40,707	18,462	41,000	100,169	52.60%	
2021/2022	66,622	40,707	18,462	41,000	100,169	50.40%	

[301] Ex. 17 at 49 (Sexton Direct).
[302] *Id.* at 50.
[303] *Id.*
[304] Ex. 5 at 13 (Lee Direct).
[305] Ex. 12 at 11 (Mead Direct); Ex. 402 at 14 (Ryan Direct).
[306] Ex. 12 at 21, Table 1 (Mead Direct). Ms. Mead is Manager of Gas Supply for MERC, and began working for a predecessor of WEC in 2000. *Id.* at 1-2.

Winter Period	Rochester Design Day	Capacity 1D	Capacity 1B	Capacity New TBS	Total Capacity	Reserve Margin	
2022/2023	67,621	40,707	18,462	41,000	100,169	48.10%	
2023/2024	68,636	40,707	18,462	41,000	100,169	45.90%	
2024/2025	69,665	40,707	18,462	41,000	100,169	43.80%	
2025/2026	70,710	40,707	0	59,462	100,169	41.70%	Re-align 1B
2026/2027	71,771	40,707	0	59,462	100,169	39.60%	
2027/2028	72,847	40,707	0	59,462	100,169	37.50%	
2028/2029	73,940	40,707	0	59,462	100,169	35.50%	
2029/2030	75,049	40,707	0	59,462	100,169	33.50%	
2030/2031	76,175	40,707	0	59,462	100,169	31.50%	
2031/2032	77,317	40,707	0	59,462	100,169	29.60%	
2032/2033	78,477	40,707	0	59,462	100,169	27.60%	
2033/2034	79,654	40,707	0	59,462	100,169	25.80%	
2034/2035	80,849	40,707	0	59,462	100,169	23.90%	
2035/2036	82,062	40,707	0	59,462	100,169	22.10%	
2036/2037	83,293	40,707	0	59,462	100,169	20.30%	
2037/2038	84,542	40,707	0	59,462	100,169	18.50%	
2038/2039	85,810	40,707	0	59,462	100,169	16.70%	
2039/2040	87,097	40,707	0	59,462	100,169	15.00%	

233. MERC also calculated the reserve margin for the same time period assuming that 20 percent of the capacity is used elsewhere on MERC's system, as is permitted under the PA. The table below shows that utilizing 20 percent elsewhere on MERC's system reduces the reserve margins in the Rochester area.

Table 2 – Rochester Capacity Staging Plan with 20% of Capacity Utilized at Alternative TBS (Dth/Day)

Winter Period	Rochester Design Day	Capacity 1D	Capacity 1B	Capacity New TBS	20% Utilized Elsewhere	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	-13,134	52,535	-17.5%	
2019/2020	64,667	40,707	18,462	41,000	-20,034	80,135	23.9%	
2020/2021	65,637	40,707	18,462	41,000	-20,034	80,135	22.1%	
2021/2022	66,622	40,707	18,462	41,000	-20,034	80,135	20.3%	
2022/2023	67,621	40,707	18,462	41,000	-20,034	80,135	18.5%	Phase I
2023/2024	68,636	40,707	18,462	41,000	-20,034	80,135	16.8%	Phase II
2024/2025	69,665	40,707	18,462	41,000	-20,034	80,135	15.0%	

Winter Period	Rochester Design Day	Capacity 1D	Capacity 1B	Capacity New TBS	20% Utilized Elsewhere	Total Capacity	Reserve Margin	
2025/2026	70,710	40,707	0	59,462	-20,034	80,135	13.3%	
2026/2027	71,771	40,707	0	59,462	-20,034	80,135	11.7%	
2027/2028	72,847	40,707	0	59,462	-20,034	80,135	10.0%	
2028/2029	73,940	40,707	0	59,462	-20,034	80,135	8.4%	Re-align
2029/2030	75,049	40,707	0	59,462	-20,034	80,135	6.8%	1B
2030/2031	76,175	40,707	0	59,462	-20,034	80,135	5.2%	
2031/2032	77,317	40,707	0	59,462	-20,034	80,135	3.6%	
2032/2033	78,477	40,707	0	59,462	-20,034	80,135	2.1%	
2033/2034	79,654	40,707	0	59,462	-20,034	80,135	0.6%	
2034/2035	80,849	40,707	0	59,462	-20,034	80,135	-0.9%	
2035/2036	82,062	40,707	0	59,462	-20,034	80,135	-2.3%	
2036/2037	83,293	40,707	0	59,462	-20,034	80,135	-3.8%	
2037/2038	84,542	40,707	0	59,462	-20,034	80,135	-5.2%	
2038/2039	85,810	40,707	0	59,462	-20,034	80,135	-6.6%	
2039/2040	87,097	40,707	0	59,462	-20,034	80,135	-8.0%	

234. MERC recognized that the addition of the new capacity under the PA results in relatively high reserve margins for the near- to mid-term, but maintained that it is reasonable in these circumstances given that there is no available existing capacity on the NNG system in the Rochester area.[307]

235. While distribution utilities generally seek to maintain a reserve margin of five percent to ensure system reliability in case the Design Day is greater than forecasted, in certain circumstances a larger reserve margin may be necessary.[308]

236. In markets such as Rochester where unsubscribed pipeline capacity is not available, new pipeline and/or compression must be installed to provide incremental capacity.[309] Because a lead time of three years or more is typically required to support facility expansions, capacity cannot be acquired on a "just-in-time" basis. Rather, in order to retain reliability, expansions must be planned years in advance, which typically results in "lumpy" development and reserve margins in excess of 5 percent after the in-service date of an expansion project.[310]

[307] Ex. 5 at 31 (Lee Direct).
[308] Ex. 17 at 11-12 (Sexton Direct).
[309] *Id.*
[310] Ex. 5 at 32 (Lee Direct); Ex. 17 at 12 (Sexton Direct).

237. In addition, larger expansion projects provide economies of scale that cannot be achieved with smaller expansion projects, which can justify a larger reserve margin.[311]

238. For these reasons, in an environment where unsubscribed capacity is not currently available, capacity is generally purchased to meet long-term growth requirements rather than simply meet near-term needs.[312] Although it may take several years to grow into the added capacity, the economies of scale from larger projects are expected to offset this concern.[313] In these circumstances, a reserve margin greater than five percent is generally necessary and reasonable.[314]

239. According to MERC, the present Petition involves one such situation. MERC reiterated that construction of the NNG pipeline project is necessary because NNG is fully subscribed on the transmission laterals that serve the Rochester area and there is no existing capacity available for purchase. In addition, the existing NNG main transmission pipelines that feed the laterals do not have adequate upstream capacity to ensure delivery of natural gas to meet the expected growth. For these reasons, MERC asserted that the PA is necessary to meet current and future growth, and the resulting reserve margins in the Rochester area are not unreasonable.[315]

240. MERC also calculated MERC's reserve margin on a system-wide basis for 2015/2016 to 2039/2040 given that the system as a whole will benefit from the PA. The table below shows the system-wide reserve margin.

Table 3 – System-Wide Reserve Margin

Winter Period	NNG Current Capacity	Additional Capacity	Total NNG Capacity	NNG Design Day	Capacity Long/Short	Percent	
2015/2016	252,127	252,127	245,263	6,864	2.80%		
2016/2017	252,127	252,127	248,942	3,185	1.28%		
2017/2018	252,127	252,127	252,676	-549	-0.22%		
2018/2019	252,127	15,939	268,066	256,466	11,600	4.52%	NNG Phase I
2019/2020	252,127	53,032	305,159	260,313	44,846	17.23%	NNG Phase II
2020/2021	252,127	53,032	305,159	264,218	40,941	15.50%	
2021/2022	252,127	53,032	305,159	268,181	36,978	13.79%	
2022/2023	252,127	53,032	305,159	272,204	32,955	12.11%	
2023/2024	252,127	53,032	305,159	276,287	28,872	10.45%	

[311] Ex. 17 at 13 (Sexton Direct).
[312] Ex. 17 at 14 (Sexton Direct).
[313] Ex. 12 at 26 (Mead Direct); Ex. 5 at 31-32 (Lee Direct).
[314] *See* Ex. 17 at 11-14 (Sexton Direct).
[315] Ex. 12 at 26-27 (Mead Direct).

Winter Period	NNG Current Capacity	Additional Capacity	Total NNG Capacity	NNG Design Day	Capacity Long/Short	Percent	
2024/2025	252,127	53,032	305,159	280,431	24,728	8.82%	
2025/2026	252,127	53,032	305,159	284,638	20,521	7.21%	
2026/2027	252,127	53,032	305,159	288,907	16,252	5.63%	
2027/2028	252,127	53,032	305,159	293,241	11,918	4.06%	
2028/2029	252,127	53,032	305,159	297,640	7,519	2.53%	
2029/2030	252,127	53,032	305,159	302,104	3,055	1.01%	
2030/2031	252,127	53,032	305,159	306,636	-1,477	-0.48%	
2031/2032	252,127	53,032	305,159	311,235	-6,076	-1.95%	
2032/2033	252,127	53,032	305,159	315,904	-10,745	-3.40%	
2033/2034	252,127	53,032	305,159	320,642	-15,483	-4.83%	
2034/2035	252,127	53,032	305,159	325,452	-20,293	-6.24%	
2035/2036	252,127	53,032	305,159	330,334	-25,175	-7.62%	
2036/2037	252,127	53,032	305,159	335,289	-30,130	-8.99%	
2037/2038	252,127	53,032	305,159	340,318	-35,159	-10.33%	
2039/2040	252,127	53,032	305,159	350,604	-45,445	-12.96%	

241. MERC noted that when considering the system as a whole, rather than just the Rochester area, the Design Day reserve margins are not as large.[316] Based on MERC's estimates, the reserve margin for the system as a whole will be 17.23 percent in 2019 with the addition of the new capacity, and decrease to 5.63 percent in 2026/2027.[317]

242. MERC provided some examples of other TBSs that are currently short of capacity and could benefit from the delivery optionality.[318]

243. MERC noted that it in the event it has excess capacity that it does not need on its system, it can mitigate the cost to its customers by releasing the extra capacity into the market. MERC stated that it actively releases capacity into the natural gas market throughout the year when it is not expected to be needed to serve its customers. MERC posts this capacity on the pipeline's Electronic Bulletin Board as notice to the market that the capacity is available and open for accepting bids. Any revenues realized from this release would revert to the benefit of MERC's customers.[319]

a. The Department's Estimate of the Reserve Margins

244. As discussed above, the Department conducted its own forecast and developed its own estimate of Design Day growth. Based on its estimate of peak demand over the forecasting period, the Department re-created MERC's reserve margin analysis

[316] Ex. 12 at 24 (Mead Direct).
[317] *Id.* at 25, Table 3.
[318] *Id.* at 28.
[319] *Id.* at 29.

to assess the impact that the Department's lower growth rate would have on the Rochester area and the MERC-NNG system reserve margins.[320]

245. The results of the Department's reserve margin analysis and calculations are provided in the table below. The results show the reserve margin for MERC's system as a whole, not just the Rochester area, and assumes that 20 percent of the capacity can be redirected if not needed in Rochester.[321]

Heinen Direct Table 1: Comparison of Excess Capacity

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

246. The Department noted that its reserve margin analysis shows that instead of the excess capacity from the Project being used up in approximately 2030, as calculated by MERC, some level of excess capacity would exist until 2040.[322]

[320] Ex. 405 at 29-20 (Heinen Direct).
[321] *Id.* at 30; Tr. Vol. 2 at 25-26 (Heinen).
[322] Ex. 403 at 31 (Heinen Direct).

247. The Department estimated the costs associated with the projected excess capacity shown in the table above. Using the estimated annual capacity costs provided in MERC's Petition, the Department calculated the costs of excess capacity on an annual and total basis, as shown the table below.[323]

Heinen Direct Table 2:
Comparison of Cost of Excess Capacity

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

248. As shown above, use of the Department's lower Design Day growth rate results in approximately $30 million more in total excess capacity costs than MERC's filed forecast for the period between 2019 and 2040.

249. In light of the projected excess capacity costs, the Department considered whether a smaller project would better meet future Design Day requirements. The Department's witness, Mr. Heinen, concluded that a smaller project could potentially

[323] *Id.* at 31-32, AJH-16.

satisfy the need but noted that the construction of a smaller project includes the risk of future expansions and greater costs.[324]

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

Heinen Direct Table 3: Comparison of Excess Capacity (25,000 Dkt/day Scenario)[325]

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

[324] Ex. 405 at 32-35 (Heinen Direct).
[325] Ex. 405 at 33 (Heinen Direct).

Heinen Direct Table 4: Comparison of Excess Capacity (35,000 Dkt/day Scenario)[326]

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

251. Mr. Heinen concluded that these incremental capacity additions would result in smaller amounts of excess capacity.[327] He noted, however, that these incremental alternatives were only viable under the Department's lower growth estimate. He cautioned that the Company would be required to purchase additional capacity and, likely, to invest in additional upgrades to serve customers in the Rochester Area if: 1) growth in the Rochester Area were closer to MERC's forecast; 2) overall system peak demand grew at MERC's forecasted rate; 3) the base peak demand in the Company's demand entitlement filing was more representative of peak demand; or 4) increased firm natural gas were needed by RPU or any other electric utility.[328]

252. In addition, the Department noted that MERC's expert, Mr. Sexton, estimated that limiting expansion capacity to 30,000 Dth/day (instead of the proposed

[326] Ex. 405 at 34 (Heinen Direct).
[327] *Id.*, AJH-17, AJH-18.
[328] *Id.* at 34-35.

45,000 Dth/day) would cost $1 million *more* on an NPV basis than the cost of the PA.[329] Mr. Sexton's analysis was based on a good faith estimate of the potential costs associated with an incremental expansion approach.[330]

253. The Department concluded that a future upgrade to serve Rochester area customers would result in additional, significant costs to MERC ratepayers.[331]

254. In addition, Mr. Heinen explained that while the excess capacity costs depicted in the table above at paragraph 247 appeared large, it is important to consider these costs into the context of annual demand and commodity costs.[332]

255. On an annual basis, MERC incurs approximately $24 million of demand costs and approximately $120 million in commodity costs, whereas the average amount of excess capacity associated with the PA may total about $3 million. In other words, the excess capacity costs may approach 2.5 percent of total PGA costs incurred, based on current prices, for the MERC-NNG PGA system.[333]

256. The Department pointed to the Bison Pipeline contract for comparison purposes. MERC-NNG ratepayers have been assessed the costs of the Bison Pipeline contract since November 2010. These costs are recovered through the commodity portion of the PGA. The capacity from the Bison Pipeline contract has been used at levels far below the full contracted capacity.[334]

257. The average costs of the Bison Contract for residential customers is $38.09 per year, while total capacity costs for the Rochester Project would be $32.16 per year for residential customers.[335]

258. The estimated excess capacity costs for the Rochester PA are embedded in the $32.16 figure. For that reason, the Department concluded that the excess costs of the not fully used Bison Contract, which ratepayers have been assessed for several years, are likely greater than the potential excess capacity costs associated with the Rochester Project.[336]

259. Based on this reserve margin analysis and its analysis of incremental capacity alternatives, the Department concluded in Direct and Rebuttal testimony that the size of MERC's proposed Project was reasonable.[337] The Department concluded the total cost associated with an incremental approach to adding capacity, or future capacity

[329] Ex. 405 at 35, AJH-19 (Heinen Direct) (MERC response to DOC IR No. 37).
[330] *Id.*
[331] *Id.* at 35.
[332] *Id.*
[333] *Id.* at 35-36.
[334] *Id.* at 36, AJH-20.
[335] *Id.*, AJH-21.
[336] *Id.* at 36.
[337] Ex. 405 at 36 (Heinen Direct); Ex. 406 at 1-3 (Heinen Rebuttal).

upgrades, would likely result in higher total costs to ratepayers than the Project as proposed. [338]

260. Further, in the Department's view, any excess costs associated with the Project as proposed by MERC are relatively small on an annualized basis and are comparable to insurance against the potential costs of future system upgrades.[339] The Department also pointed out that MERC could mitigate the costs of excess capacity going forward through capacity release sales.[340]

261. The Department suggested that excess capacity could be sold on the open market through capacity release. Capacity release is the act of placing unneeded capacity on the open market for other parties to purchase to satisfy their natural gas needs. Generally the capacity is sold on a short-term basis.[341] Historically, MERC has received an average of $625,000 in capacity release credits each year since 2007. [342]

262. The revenue associated with capacity release sales is usually small compared to the original purchase price of the capacity because it is usually sold on a short-term basis.[343] Long-term capacity release sales can be more profitable. For that reason, the Department recommended that MERC explore options for long-term capacity release of excess capacity if the Project is approved.[344]

263. As another means of mitigating excess capacity, the Department recommended that the Company explore trying to move interruptible customers to firm service.[345]

264. In Surrebuttal Testimony, the Department reaffirmed its conclusion that the size of the NNG contract is reasonable. The Department updated it excess capacity analysis to include RPU's future gas consumption. The Department pointed to information in the record showing that RPU plans to add new natural gas electric facilities to its fleet in 2018, 2026 and 2031.[346] While RPU indicated that it plans to take interruptible transportation service for the new facilities**,** the Department included these RPU projections because RPU will be using some of the excess capacity for these new electric generation facilities and paying for its use. In addition, the Department asserted that RPU may use some of the additional capacity in the near term for one of its existing plants, Cascade Creek. Cascade Creek is currently subject to curtailment several times each winter when gas supply is not sufficient to operate at full capacity. As a result, the

[338] Ex. 405 at 35 (Heinen Direct).
[339] *Id.* at 37.
[340] *Id.* at 37, 46-48.
[341] *Id.* at 47.
[342] *Id.*
[343] *Id.* at 47-48.
[344] *Id.*
[345] Ex. 405 at 59-60 (Heinen Direct); Ex. 410 (Heinen Opening Statement).
[346] Ex. 407 at 16-17 (Heinen Surrebuttal); *see also* Ex. 309, JAU-R-2 (Urban Rebuttal Schedules).

Department concluded that RPU's use will reduce the excess capacity even if RPU is not a firm customer.[347]

265. Using his prior assumptions and analysis and an estimated average daily consumption for each RPU generation facility identified in Dr. Urban's Rebuttal Schedules, the Department provided updated results, as shown in the table below.[348]

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

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

266. The Department concluded from this updated analysis that the addition of natural gas-fired generation by RPU was likely to appreciably decrease MERC's excess capacity.[349]

[347] Ex. 407 at 16-18 (Heinen Surrebuttal).
[348] *Id.* at 18.
[349] *Id.*

267. In addition, the Department updated its calculation of the cost of excess capacity assuming MERC negotiates maximum rates for capacity release. The updated results are set forth in the table below.[350]

Heinen Surrebuttal Table S-3:
Updated Comparison of Cost of Excess Capacity

Year	MERC Cost of Excess Capacity	DOC Cost of Excess Capacity (Preferred Case)
2019	$2,192,622	$2,333,898
2020	$5,644,228	$6,300,355
2021	$5,112,325	$5,938,101
2022	$4,559,180	$5,552,642
2023	$4,008,553	$5,170,440
2024	$3,445,534	$4,770,757
2025	$2,913,606	$4,413,485
2026	$1,639,832	$3,308,958
2027	$1,108,287	$2,947,515
2028	$577,725	$2,578,910
2029	$55,628	$2,235,404
2030	$0	$1,885,667
2031	$0	$1,013,593
2032	$0	$767,585
2033	$0	$518,920
2034	$0	$267,571
2035	$0	$0
2036	$0	$0
2037	$0	$0
2038	$0	$0
2039	$0	$0
2040	$0	$0
Total	$31,257,522	$50,003,801

268. After evaluating this updated analysis and considering the potential risks and cost considerations of building a smaller project, it remained the Department's conclusion that the Project, as proposed, is reasonable.[351]

[350] Ex. 407 at 19 (Heinen Surrebuttal).
[351] *Id.* at 4.

b. The OAG's Review of the Reserve Margins and Excess Capacity

269. The OAG contended that the Rochester Project results in too much excess capacity and also provides that capacity earlier than necessary even assuming that MERC's forecast is accurate.[352] The OAG argued that the 45,000 Dth/day provided for in the PA is more than is needed to serve the Rochester area.[353]

270. The OAG pointed to the following table that provides an overview of excess capacity over time for the Rochester area. This table was developed by MERC in response to DOC IR No. 15, and is substantially similar to MERC's Table 1 set forth above in paragraph 232.[354]

Rochester Staging Plan (45,000 Dth/Day)

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

[352] Ex. 300 at 36 (Urban Amended and Corrected Direct).
[353] *Id.* at 36-37.
[354] *Id.* at 39.

2038/2039	84,460	40,707	0	59,462	100,169	18.60%
2039/2040	85,726	40,707	0	59,462	100,169	16.85%

271. The OAG asserted that while capacity expansions are expected to be "lumpy," with excess capacity to allow for future growth, the table shows that the reserve margin for Rochester will exceed 16 percent to the year 2040. The OAG's witness, Dr. Urban, argued that a reserve margin of 16 percent would be higher than ratepayers should be required to pay for and maintained that ratepayers will be receiving essentially no benefit from the reserve margin. Dr. Urban stated that a reserve margin of up to five percent would be considered reasonable.[355]

272. Based on these projected reserve margins, the OAG asserted that MERC's proposal seeks to "put current ratepayers on the hook" for infrastructure upgrades and gas supply that will not be useful for decades and that MERC's proposal results in overbuilding the system.[356]

273. The OAG disagreed with MERC's analysis of the amount of excess capacity that will exist in the Rochester area and system-wide with the addition of 45,000 Dth/day. The OAG asserted that MERC's analysis, as displayed in Table 2 at paragraph 233, improperly assumes that 20,000 Dth/day will be used on other parts of MERC's system. The OAG maintained that there is no evidence that other delivery points on MERC's system will have demand for that much additional capacity and, even if they do, there is no guarantee that the capacity can be delivered to alternate points at times of high demand.[357] Second, with regard to MERC's calculation of the system-wide reserve margin set forth in Table 3 above at paragraph 240, the OAG argued that a system-wide analysis should be given minimal weight because the focus of this proceeding is on the need in the Rochester area.[358]

274. The OAG also disagreed with the Department's view that consumption by RPU should be considered in evaluating the Project. The OAG noted that the Project is intended to meet Design Day needs of firm customers, and RPU has indicated that it intends to take interruptible transportation service, not firm service, to meet its future electric generation needs.[359]

275. Finally, the OAG questioned the Department's comparison of this Project to the Bison Pipeline Project in terms of the relative cost of the excess capacity. The OAG argued that the Bison Pipeline Project does not justify the costs of the projected excess capacity but rather provides an example of problems that can result from pipeline contracts.[360]

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[355] Ex. 300 at 37 (Urban Amended and Corrected Direct).
[356] *Id.* at 38.
[357] OAG Initial Br. at 14 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
[358] *Id.*
[359] *Id.* at 69-71.
[360] *Id.* at 72.

c. The OAG's Discussion of Alternatives

276. Based on its conclusion that MERC's request for incremental capacity of 45,000 Dth/day is more than is necessary, the OAG asserted that a smaller capacity addition would have produced more reasonable reserve margins.[361]

277. The OAG highlighted that NNG provided several phased proposals for MERC's consideration during the RFP stage that could have incrementally added capacity to the system.[362] According to the OAG, these phased proposals could have minimized the risk associated with forecasting, while still permitting future expansion if growth materializes in the future. In the OAG's view, this would reduce the risk to MERC's customers for costs associated with overbuilding facilities for forecasts of unknown growth.[363]

278. The OAG's witness, Dr. Urban, focused on NNG's Proposal 4.2 in particular. Phased Proposal 4.2 would have increased existing 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 about 100,000 Dth/day (including the existing 55,169 Dth/day).[364]

279. Dr. Urban asserted in Rebuttal Testimony that the total cost for Phased Proposal 4.2 is lower than MERC's proposal.[365] Dr. Urban later acknowledged Proposal 4.2 and the other phased options offered by NNG that would allow cancelation or delay of the second phase, include a price risk for the second phase.[366]

280. In the OAG's view, a phased approach that allows MERC the option of future capacity additions when they are needed would provide significant benefits to ratepayers. The OAG noted that Phased Proposal 4.2 would provide enough capacity in the initial phase to address the Rochester Design Day needs "for more than a decade" and would have much lower up-front costs than the PA.[367] In addition, this approach (and other phased approaches) would more closely tie the costs to ratepayers who may need the facilities, resulting in greater equity. Finally, later costs could be avoided or delayed if MERC's forecast is too high, which would remove a significant portion of forecasting risk.[368] The OAG also pointed to recent news reports about a delay in the development of a Rochester residential and retail tower to question whether the DMC plan would

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361 Ex. 300 at 40 (Urban Amended and Corrected Direct).
362 Ex. 300 at 43, 49 (Urban Amended and Corrected Direct).
363 *Id.* at 49.
364 *Id.* at 24.
365 Ex. 307 at 14 (Urban Amended and Corrected Rebuttal).
366 Tr. Vol. 1 at 175 (Urban); *see also* Ex. 306, JAU-5 at 39-40 (Urban Direct Schedules) (discussing Proposal 4.2 and noting that the cost of the second phase is not fixed but would be based on actual cost at the time). NNG also offered a fixed price option for Proposal 4.2 but this option did not allow for cancelation or delay of the second phase and was more expensive than Proposal 3.0. *See* Ex. 306, JAU-5 at 41 (Urban Direct Schedules).
367 OAG Reply Br. at 27 (Oct. 25, 2016) (eDocket No. 201610-125991-01); OAG Initial Br. at 51-52 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
368 Ex. 307 at 9-10 (Urban Amended and Corrected Rebuttal); OAG Initial Br. at 51-52 (Oct. 11, 2016) (eDocket No. 201610-125583-01).

materialize as envisioned.[369] The OAG concluded that it would be "much more prudent for MERC to take a more incremental approach such as the phase in proposal similar to Proposal 4.2."[370]

281. In addition, the OAG asserted that MERC should have given more consideration to conservation and "peak-shaving" facilities as means of reducing the capacity needs for the Rochester area.[371]

282. While MERC discussed conservation as an alternative in its Petition,[372] the OAG maintained that MERC should have provided significantly more information about the possibility that conservation could reduce peak demand in the Rochester area and reduce the need for the Rochester Project.[373]

283. The OAG also argued that MERC should have provided information in its Petition about the possibility that peak-shaving facilities could be used to mitigate Design Day demand.[374] Peak-shaving facilities are systems that allow natural gas utilities to minimize the impact of unpredictable shifts in daily or hourly consumptions, as well as other unexpected supply constraints, by augmenting natural gas fuel supply during times of high demand. During periods of extreme usage, peaking shaving facilities, as well as other sources of temporary storage, can be utilized to supplement system and underground storage supplies.[375]

284. The OAG noted that CenterPoint and Xcel both utilize peak-shaving facilities to help meet Design Day firm demand.[376] The OAG also emphasized that, across the state, over 20 percent of utilities' demand day requirements are met by peak-shaving facilities.[377] The OAG's witness, Dr. Urban, recognized that she did not have "the information or expertise to allow for the analysis that would lead to [] a recommendation" that MERC add a peak-shaving facility, and reiterated that her "main criticism is MERC's approach to its analysis of alternatives."[378]

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369 Ex. 307 at 15 (Urban Amended and Corrected Rebuttal).
370 *Id.* at 16. Dr. Urban also asserted that the approximately 17,500 Dth/day increase in Phase I would provide a reserve margin above 4 percent to the year 2026. *Id.*; Ex. 309, JAU-R-3 (Urban Rebuttal Schedules). It should be noted that Dr. Urban uses a 2015/2016 Design Day that is 960 dekatherms less than MERC's 2015/2016 Design Day. *Compare* Ex. 309, JAU-R-3 (Urban Rebuttal Schedules), *with* Ex. 12 at 21, Table 1 (Mead Direct).
371 OAG Initial Br. at 64 (Oct. 11, 2016) (eDocket No. 201610-125583-01); Ex. 300 at 50-54 (Urban Amended and Corrected Direct).
372 Ex. 1 at 27 (Petition).
373 OAG Initial Br. at 64 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
374 Ex. 300 at 50-52 (Urban Amended and Corrected Direct).
375 Ex. 25 at 2-3 (Lyle Opening Statement); Ex. 300 at 53 (Urban Amended and Corrected Direct).
376 Ex. 300 at 53 (Urban Amended and Corrected Direct).
377 *Id.*
378 *Id.* at 55.

d. The OAG's Comments on MERC's Phase II Distribution Upgrades

285. The OAG's witness, Dr. Urban, also expressed concern regarding the appropriateness of MERC's distribution upgrade plan.[379] Dr. Urban argued that there should be more clarity and transparency before the distribution upgrades of Phase II are approved, arguing that MERC appears to be building in a margin for growth error with respect to its distribution upgrades that the Company has not demonstrated to be reasonable.[380]

e. The OAG's Conclusion

286. In the OAG's view, MERC's proposal for the Rochester Project, including the PA and Phase II plans for proposed distribution infrastructure upgrades, exceeds capacity needs, possibly for many years beyond 2040.[381]

287. Based upon the concerns set forth above, the OAG argued that MERC had not demonstrated that its Project is a reasonable way to meet future demand for natural gas in the Rochester area. The OAG recommended that the Commission order MERC to find an alternate solution, such as a phased proposal like the ones offered by NNG.[382]

3. MERC's Response to the OAG

288. MERC disagreed with the OAG's concerns and conclusion, for the reasons addressed below.[383]

a. Excess Capacity

289. With regard to projections of excess capacity, MERC asserted that it is more appropriate to look at the reserve margin of the entire MERC-NNG PGA, not just that for the Rochester area.[384] According to MERC, the Department and Commission have always reviewed demand entitlements, design day requirements, and reserve margins on a PGA-wide basis because of the ability to move natural gas to alternate delivery points on the system.[385] MERC noted that it will have the ability to use "up to 20 percent of the total Rochester existing and expansion entitlement and 100 percent of the Southeastern Minnesota expansion entitlement (nearly 53 percent of the total expansion volume) on an alternate basis to locations throughout MERC's service area on NNG's system."[386]

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[379] *Id.* at 43.
[380] *Id.* at 44.
[381] Ex. 300 at 44 (Urban Amended and Corrected Direct).
[382] *Id.* at 57.
[383] *See* Ex. 6 (Lee Rebuttal); Ex. 10 (Clabots Rebuttal); Ex. 11 (Clabots Surrebuttal); Ex. 13 (Mead Rebuttal); Ex. 14 (Mead Rebuttal).
[384] MERC Initial Br. at 36 (Oct. 11, 2016) (eDocket No. 201610-125589-01).
[385] *Id.*
[386] Ex. 27 at 2 (Mead Opening Statement).

290. According to MERC, when looking at MERC's system as a whole, the additional capacity to be added by the PA does not result in an unreasonable reserve margin. MERC noted that it estimated that the Design Day in 2019/2020 would be about 17 percent, declining down to less than six percent by 2026/2027.[387]

b. Alternatives

291. With regard to alternatives, MERC disagreed with the OAG's view that MERC should have selected a smaller project or one that could be phased-in more precisely to match the increase in capacity with demand growth. MERC asserted that the OAG's preference for a phased approach would subject MERC's customers "to undue risk and increased costs."[388]

292. MERC maintained that meeting long-term demand requirements through a single larger-scale expansion project like the Rochester Project has several advantages, including: 1) a single large-scale project has the potential to result in long-term design efficiencies with resulting lower costs than a series of small-scale projects; 2) a single large-scale project can provide cost savings associated with economies of scale versus a series of small-scale projects; 3) large-scale expansion projects support the introduction of potential competitive alternatives as there can be large barriers to entry with small-scale expansions that prevent competitive service providers from entering a market; 4) large-scale expansion projects can provide long-term growth capacity to the local market whereas small-scale expansion projects can result in ongoing short-term capacity shortfalls due to project timing requirements; and 5) growth capacity provided by large-scale expansion projects is available to support ongoing economic development and/or unforeseen demand growth.[389]

293. With regard to the specific proposals put forth by NNG, MERC witness Sarah Mead stated in Rebuttal Testimony that MERC did consider all of the phased proposals presented by NNG.[390] MERC also provided specific detail regarding the deficiencies of phased proposals.[391]

294. With regard to Proposal 4.2 in particular, MERC noted two operational issues. First, the new capacity would be provided at TBS 1B, which is not where MERC's substantial growth is occurring, according to Ms. Mead. Second, the proposed in-service dates pushed the second phase out too far, according to MERC.[392]

295. In addition, MERC noted that all of the phased proposals that allowed for delay or cancelation of the second phase, including Proposal 4.2, did not include a fixed rate. Instead, the rate for the second phase would be contracted for with NNG at a later

[387] MERC Initial Br. at 37 (Oct. 11, 2016) (eDocket No. 201610-125589-01); Ex. 12 at 24-25 (Mead Direct).
[388] Ex. 27 at 2 (Mead Opening Statement).
[389] Ex. 17 at 15 (Sexton Direct).
[390] Ex. 13 at 11-12 (Mead Rebuttal).
[391] Ex. 19 at 13-15 (Sexton Rebuttal); Ex. 17 at 42 (Sexton Direct) (NNG provided one proposal that met MERC's RFP terms).
[392] Ex. 16 at 17 (Mead Surrebuttal).

date based on actual costs incurred at the time of construction.[393] In MERC's view, this would place MERC and its customers at risk that NNG would charge additional compensation for the second phase.[394] MERC's witness, Mr. Sexton, stated that "it is a near certainty that costs of a later incremental capacity expansion negotiated in a non-competitive environment with NNG would result in higher costs than will be paid for this growth in capacity in the current transaction."[395]

296. MERC also stated that it did not confine itself to following any particular proposal. Instead, it worked with NNG to design a modified proposal for 45,000 Dth/day, which MERC maintains provided "significant additional value for MERC's customers at the best possible price."[396] For these reasons, MERC asserted that none of NNG's phased proposals would be more reasonable for meeting the current and future capacity needs than is the PA.[397]

297. MERC also maintained that a smaller capacity contact, such as a 30,000 Dth/day contract with no option to expand to 45,000 Dth/day, would not have been more reasonable than the 45,000 Dth/day PA with NNG. MERC witness Mr. Sexton calculated that adding incremental capacity totaling 30,000 Dth/day, instead of the proposed 45,000 Dth/day PA, resulted in a Net Present Value approximately $1 million higher than the costs of the proposed project.[398] According to Mr. Sexton, the reason that a 30,000 Dth/day project is estimated to cost $1 million more than the 45,000 Dth/day PA is that the smaller project would still require the unavoidable costs of new pipe and added compression.[399] In addition, MERC was able to negotiate a favorable price for the 45,000 Dth/day PA because of the competitive pressure NNG felt from the RFP, which was framed to solicit bids from multiple pipelines.[400]

298. MERC maintained that the Company could have sought a smaller solution to the immediate and short-term future forecasted deficiencies of capacity in the Rochester area, but such a smaller project would have come with significant risk that Design Day growth would outpace the available additional capacity, resulting in the need for even more expensive additional incremental capacity later.[401]

299. With respect to RPU's plans, MERC asserted that if it were to proceed with a smaller capacity increase, the addition of future natural gas generation facilities by RPU

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[393] Tr. Vol. 1 at 175-176 (Urban) ("Q. Would you agree with me that under the Northern package of bids as proposed, … that would allow MERC to stop and not implement the second phase, … came with the price risk that the second phase would be at actual costs at the time incurred? A. Yes.").
[394] MERC Initial Br. at 33 (Oct. 11, 2016) (eDocket No. 201610-125589-01).
[395] Ex. 28 at 3 (Sexton Opening Statement).
[396] Ex. 16 at 16 (Mead Surrebuttal).
[397] MERC Initial Br. at 32-36 (Oct. 11, 2016) (eDocket No. 201610-125589-01).
[398] Ex. 13 at 7-8 (Mead Rebuttal); Ex. 405 at 35, AJH-19 (Heinen Direct).
[399] Ex. 28 at 3 (Sexton Opening Statement).
[400] *Id.*
[401] Ex. 13 at 8-9 (Mead Rebuttal).

would likely trigger the need for additional and potentially redundant infrastructure in the future.[402]

300. MERC stressed that pursuing another project in the next several years raises concerns about additional disruption in the community and also raises concerns over the timing of adding more infrastructure on the heels of the hypothetical smaller project preferred by the OAG. By designing the Project the way it did, MERC asserted it insured against the need for additional and potentially redundant projects to serve potential increased demand from the DMC, as well as the increased needs identified by RPU.[403]

301. MERC stated that the reserve margin from the Project provides insurance to mitigate against future growth and the risk of future upgrades, and that pursuit of smaller incremental projects would expose MERC's customers to excessive risk.[404]

302. The Department noted, and MERC agreed, that the OAG failed to consider the risks and costs associated with a smaller or phased alternative if demand grows as projected. Both MERC and the Department concluded it is unreasonable to fail to consider the risks which would likely represent a significant increase in costs for MERC's ratepayers, given the expectation that MERC provide reliable service.[405]

c. Conservation

303. With regard to the OAG's assertion that MERC's analysis of conservation was incomplete, MERC noted that the OAG raised this argument for the first time in its brief.[406] MERC also responded that it discussed conservation as an alternative in its initial filing, and determined that conservation is not a viable alternative.[407] According to MERC's calculations, conservation in the Rochester area would have to increase enormously to avoid the need to expand the capacity of the pipeline and capacity of the distribution system in the area.[408] MERC also asserted that reliance on conservation to meet peak demand is not reasonable for a gas utility with an obligation to ensure adequate and reliable natural gas service to its firm customers during the coldest days because conservation efforts have a minimal impact on the demand on the coldest days during the year.[409]

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[402] Ex. 16 at 5-6 (Mead Surrebuttal).
[403] *Id.*
[404] Ex. 16 at 4 (Mead Surrebuttal).
[405] Ex. 407 at 5-6 (Heinen Surrebuttal).
[406] MERC Initial Br. at 25 (Oct. 11, 2016) (eDocket No. 201610-125589-01).
[407] *Id.* at 26.
[408] Ex. 1 at 27 (Petition).
[409] MERC Initial Br. at 26-27 (Oct. 11, 2016) (eDocket No. 201610-125589-01).

d. Peak Shaving

304. With regard to peak shaving, MERC stated that it did consider peak shaving early in the planning process as an alternative to meet peak demand and determined that such facilities would not solve MERC's capacity need in the Rochester area.[410]

305. MERC explained that a thorough evaluation of peak-shaving alternatives was not undertaken because use of peak-shaving facilities would not effectively serve the deficit MERC currently has in the Rochester area.[411]

306. MERC's Engineering Manager, Lindsay Lyle, testified that "MERC looked at options to fill that peak demand." Ms. Lyle stated that MERC previously had "a peak shaving plant in Rochester that was retired and sold in 2006." The unit was retired "due to the high cost to maintain, install, and operate the peak shaving [unit]…."[412] Ms. Lyle also indicated that to provide additional capacity to Rochester, a peak-shaving facility would need to be injected into MERC's high-pressure system, as opposed to its low-pressure system, which presents complicated technical issues. For these reasons, MERC determined peak shaving was not a viable option early in the process.[413]

4. Rochester's Renewable Energy Plans Will Not Diminish the Need for Increased Gas Capacity

307. In determining whether the Rochester Project is a reasonable and prudent means of meeting MERC's future capacity needs in the Rochester area, the Commission is required to consider the utility's obligation to provide reliable service and the need to ensure that rates are just and reasonable.[414]

308. In conducting this evaluation, the Commission requested that the Administrative Law Judge "tak[e] into account the City of Rochester's announced goal of using 100 [percent] renewable energy by 2031."[415]

309. The Mayor of Rochester has issued a proclamation stating that the City of Rochester will use 100 percent renewable energy by 2031, but the proclamation does not have the force of law.[416]

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[410] Ex. 8 at 7-9 (Lyle Rebuttal); Ex. 25 at 1 (Lyle Opening Statement).
[411] Ex. 8 at 8-9 (Lyle Rebuttal).
[412] Tr. Vol. 1 at 63-64 (Lyle); Ex. 7 at 1 (Lyle Direct). Ms. Lyle has a degree in Chemical Engineering and has been employed in the natural gas industry since 1999. Ex. 7 at 1 (Lyle Direct).
[413] Tr. Vol. 1 at 63-64 (Lyle).
[414] Minn. Stat. §§ 216B.03-.04.
[415] NOTICE AND ORDER FOR HEARING at 5 (eDocket No. 20162-118054-01).
[416] Ex. 300, JAU-33 (Urban Direct) (Correspondence from Mark Kotschevar, General Manager of Rochester Public Utilities, to Ryan P. Barlow, Assistant Attorney General).

310. In addition, the Rochester City Council has not formally ratified the 100 percent renewable energy proclamation, and no work has been done to analyze the cost or feasibility of accomplishing the goal.[417]

311. The City's most recent energy plan includes a goal of 25 percent renewable energy by 2025. It also recognizes that additional natural gas resources are and will be needed to serve the Rochester area.[418]

312. No party to this proceeding asserted that the City of Rochester's plans to increase its use of renewable energy will reduce the need for the Rochester Project.

313. In summary, there is no evidence in the record that the City of Rochester's renewable energy plans will limit the need for the Project or affect the size of the Project.

5. Analysis of Need and Reasonableness of the Rochester Project

314. The Administrative Law Judge finds that the record demonstrates that the Rochester Project is necessary, reasonable, and prudent to provide service to MERC's customers in the Rochester area.

315. The PA and Phase II will address the existing interstate capacity constraints and distribution system issues in the Rochester area.

316. The PA will provide additional interstate capacity to meet current and future projected Design Day needs in the Rochester area.[419]

317. The PA will also help to ensure reliability on MERC's system as a whole. The PA allows MERC to utilize up to 20 percent of the Rochester capacity for delivery elsewhere in MERC's NNG PGA area, increasing MERC's ability to utilize the capacity where it is needed daily.[420]

318. While the reserve margins resulting from the PA are relatively large when looking at the Rochester area alone, the reserve margins for MERC's system as a whole are much smaller.[421] The reserve margin for the system as a whole is projected to be at 5.63 percent by 2026/2027, approximately 10 years from now.[422]

319. It is appropriate to consider the resulting reserve margins not just in Rochester but also on MERC's system as a whole because a substantial majority of MERC's operations is served by the NNG interstate pipeline.[423]

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[417] *Id.*
[418] Comment by Ardell Brede, City of Rochester (July 26, 2015) (eDocket No. 20168-124373-01).
[419] Ex. 12 at 20-23 (Mead Direct).
[420] *Id.* at 22.
[421] *Id.* at 21-25.
[422] *Id.* at 25 (Table 3 - System Wide Reserve Margin).
[423] *Id.* at 23; Tr. Vol. 1 at 104 (Mead) (discussing the ability of MERC to move gas from the Rochester TBSs to other parts of its system).

320. Given the uneven nature of capacity additions and the time it takes to plan for new capacity additions, the Administrative Law Judge concludes that the reserve margins resulting from the PA are reasonable under the circumstances especially given the DMC initiative.[424]

321. In addition, to the extent excess capacity exists in the near term, MERC can seek to sell the excess capacity on the capacity release market. Given that NNG currently has no excess capacity on its system in the Rochester area, MERC should have strong demand for any excess capacity.[425]

322. The question raised by the OAG is whether a phased project or a smaller sized project would be a more reasonable and cost-effective approach to meeting MERC's current and future capacity needs in the Rochester area. As discussed above, the OAG noted that such an approach would result in lower costs in the near term, resulting in the costs being tied more closely to those who have the Design Day need. The OAG also emphasized that MERC could cancel or delay the second part of the phased proposals if the future growth is less than expected.

323. While the OAG has raised important issues for consideration, in the view of the Administrative Law Judge neither a phased option nor a smaller project is more reasonable than the PA. Given that the Design Day is expected to grow in Rochester and on the NNG system as a whole, the Administrative Law Judge agrees with the Department and MERC that a phased project or smaller project would expose MERC's customers to a significant risk that they would pay much more for capacity over the next 25 years than under the PA.[426] The cost of the additional capacity under either a phased approach or a smaller project would be negotiated in the future. Because NNG is likely to raise its rates in the interim and MERC will again be a captive customer, there is a serious risk that MERC and its customers will pay significantly more than under the fixed-priced PA.

324. In addition, many of the phased proposals had operational issues as discussed above. Also, a smaller project in the range of 30,000 Dth/day would likely cost more than the PA because MERC would not be able to generate bids for a project that size from suppliers other than NNG. The significant cost barriers to entry in the Rochester market gives NNG a significant, if not overwhelming, competitive advantage on a smaller project.[427]

[424] Ex. 12 at 26 (Mead Direct); Ex. 17 at 13-14, 37-38 (Sexton Direct).
[425] Ex. 405 at 47 (Heinen Direct); Ex. 407 at 13 (Heinen Surrebuttal).
[426] Ex. 28 at 2-3 (Sexton Opening Statement); Ex. 13 at 14-21 (Mead Rebuttal); Ex. 405 at 34-37 (Heinen Direct); Ex. 407 at 5-6 (Heinen Surrebuttal).
[427] Ex. 13 at 7-8 (Mead Rebuttal); Ex. 405 at 35, AJH-19 (Heinen Direct); Ex. 28 at 3 (Sexton Opening Statement).

325. The Administrative Law Judge also finds that the record demonstrates that conservation and peak shaving are not viable alternatives to the PA for addressing the current and future capacity needs in the Rochester area.[428]

326. For these reasons, the Administrative Law Judge concludes the record demonstrates that the PA is necessary, reasonable, and prudent, provided that MERC actively and aggressively seeks to sell any excess capacity on the capacity release market.[429]

327. In addition, the record also supports the need and reasonableness of the Phase II distribution upgrades. The Phase II distribution system upgrades are needed to address operational and efficiency issues on MERC's distribution system in the Rochester area. Phase II involves reconstruction of the TBSs that serve Rochester and construction of transmission infrastructure necessary to move additional capacity into the Rochester area.[430]

328. In summary, the Administrative Law Judge concludes that MERC has demonstrated that the Rochester Project is prudent, reasonable, and necessary to provide reliable service to MERC's Rochester's service area, subject to the conditions set forth in the Recommendations section below.[431]

IX. The OAG's Used and Useful Recommendation

329. As discussed above, the OAG recommended that the Commission find that the Rochester Project is not necessary, reasonable or prudent. Alternatively, if the Commission finds the Project to be reasonable and prudent, the OAG recommended that the Commission find that only a portion of the Rochester Project is used and useful – "that part that is necessary to serve existing demand plus a reasonable reserve margin in 2025" such as five percent.[432] According to the OAG, the purpose of such a finding would be "to allow MERC to move forward with the Project, but protect ratepayers from overbuilding capacity until such time as that capacity becomes necessary, or used and useful."[433]

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428 While MERC's testimony and evidence regarding these issues was sufficient, the Administrative Law Judge recommends that MERC provide additional detail about such options in its initial filing if it requests approval of another project under the NGEP statute in the future.

429 Given that this is the first case under the new NGEP statute, the Administrative Law Judge recognizes that the Commission may conclude that policy considerations such as keeping rates lower in the short term or promoting generational equity should be given greater weight than the long run costs. Under such an analysis, the record could support the conclusion that a phased approach may be more reasonable than the PA. Absent specific direction for the Commission as to these policy considerations, the Administrative Law Judge's conclusions are based on consideration of the competing policy concerns identified by the parties and the record as a whole as discussed above.

430 Ex. 5 at 10 (Lee Direct); Ex. 7 at 3-5 (Lyle Direct); Ex. 405 (Heinen Direct). The distribution system upgrades would have been necessary even if MERC had negotiated for a phased approach like Proposal 4.2. Tr. Vol. 1 at 115-116 (Mead).

431 NOTICE AND ORDER FOR HEARING at 5 (eDocket No. 20162-118054-01).

432 Ex. 300 at 57-58 (Urban Amended and Corrected Direct).

433 *Id.* at 58.

330. MERC disagreed with the OAG's alternative recommendation, asserting that it is inconsistent with established ratemaking concepts and the NGEP statute.[434]

331. MERC argued that neither general principles nor the NGEP statute support the notion of partial approval or a finding of partial prudence, and that the type of partial approval suggested by the OAG should not be adopted by the Commission.[435]

332. According to MERC, if the Commission finds the Project is reasonable and prudent, then it should be eligible for cost recovery. If the Commission does not agree, then it should deny approval of the Project.[436]

333. MERC also disagreed with the OAG's view that the Rochester Project is larger than necessary. Given consideration of the specific factors relevant in Rochester, the Company asserted that the short-term capacity reserve margins that will result under the proposed Project are prudent and reasonable.[437]

334. MERC stated that if the Commission disapproves the Project or only partially approves cost recovery, then MERC will not move forward with Phase II or the PA. MERC maintained that, in that scenario, it would not be able to reliably serve its existing firm customers in and around Rochester.[438]

335. Based on a review of the applicable statutes, the Administrative Law Judge concludes that the OAG's recommendation is not supported by the law.

336. The "used and useful" standard referred to by the OAG is found in Minn. Stat. § 216B.16, the statute governing rate cases.

337. The Commission's review of the Rochester Project is under a separate statute, Minn. Stat. § 216B.1638, the NGEP statute. The standard provided in that statute is whether the project costs are "reasonable and prudently incurred" to extend natural gas service to an unserved or inadequately served area.[439] There is no requirement that capacity be limited to that necessary to serve a given area for a limited period of time as suggested by the OAG.

338. Because the OAG's recommendation would impose a standard not found in the plain language of the NGEP statute, the Administrative Law Judge recommends that the Commission not adopt the OAG's alternative recommendation.

X. Cost Recovery and Rate Design

339. If the Commission finds that the Rochester Project is needed, reasonable, and prudent, the Commission will need to determine how the costs for the Project are

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[434] Ex. 6 at 35 (Lee Rebuttal).
[435] *Id.*
[436] *Id.*
[437] *Id.* at 38.
[438] Ex. 6 at 35-36 (Lee Rebuttal).
[439] Minn. Stat. § 216B.1638, subd. 3.

recovered. MERC has proposed to recover the Project costs through three different cost recovery mechanisms: base rates, the NGEP rider, and the NNG PGA.[440]

340. More specifically, in its recent rate case MERC proposed to recover approximately $5.6 million through base rates.[441] This request was recently approved.[442]

341. With regard to Phase II, MERC proposes to recover costs of approximately $44 million through future rates case filings and through a NGEP rider.[443] Up to 33 percent of Phase II costs not recovered in base rates would be recovered through a NGEP rider.[444] MERC proposed to recover the Phase II costs from all MERC customers, including interruptible customers and transportation customers.[445]

342. Finally, approximately $60 million in NNG capital costs would be recovered through monthly capacity payments over a 25-year period through MERC's NNG PGA from MERC's customers in the NNG PGA area.[446]

343. The OAG and Department have raised issues regarding MERC's cost recovery proposal. These issues include: NGEP rider eligibility; a soft cap on Phase II costs; Phase II rate design; and recovery of NNG costs. Each is discussed in turn below.

A. NGEP Rider Eligibility

344. The NGEP statute, Minn. Stat. § 216B.1638, permits gas utilities to petition to recover costs associated with a "natural gas extension project" outside of a general rate case through implementation of a NGEP rider.

345. The NGEP statute provides that the Commission "shall approve a public utility's petition for a rider to recover the costs of a natural gas extension project if it determines that: (1) the project is designed to extend natural gas service to an unserved or inadequately served area; and (2) project costs are reasonable and prudently incurred."[447]

346. The NGEP statute defines the term "natural gas extension project" as "the construction of new infrastructure or upgrades to existing natural gas facilities necessary to serve currently unserved or inadequately served areas."[448]

[440] Ex. 5 at 17 (Lee Direct).
[441] *Id.* at 4.
[442] *See* Ex. 5 at 2, 4 (Lee Direct); *In re Application of Minn. Energy Res. Corp. for Auth. to Increase Rates for Natural Gas Serv. in Minn.*, MPUC Docket No. G-011/GR-15-736, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 8, 54 (Oct. 31, 2016).
[443] Ex. 5 at 4, 17 (Lee Direct).
[444] *Id.* at 17.
[445] Ex. 1 at 4 (Petition).
[446] Ex. 5 at 4, 17 (Lee Direct).
[447] Minn. Stat. § 216B.1638, subd. 3(b).
[448] *Id.*, subd. 1(e).

347. The phrase "unserved or inadequately served area" is defined in the statute to mean "an area in this state lacking adequate natural gas pipeline infrastructure to meet the demand of existing or potential end-use customers."[449]

1. MERC's Position

348. MERC asserted that its Rochester Project meets the criteria for cost recovery under a NGEP rider because the project involves "the construction of . . . upgrades to existing natural gas facilities necessary to serve [an] inadequately served area."[450] MERC asserted that the Rochester area is an "inadequately served area" because it "lack[s] adequate natural gas pipeline infrastructure to meet the demand of existing or potential end-use customers."[451]

2. The Department's Position

349. The Department agreed with MERC that the Rochester Project is eligible for rider recovery under Minn. Stat. § 216B.1638.[452]

350. The Department asserted that the record demonstrates that the Rochester area is an "inadequately served" area within the meaning of the NGEP statute and the Project is being constructed for purposes of extending service to the "inadequately served area."[453]

351. The Department noted that MERC's load data for the Rochester area shows that firm usage is currently at or above deliverable levels.[454] As a result, it is unlikely that MERC will be able to adequately serve existing or new customers "on a going-forward basis."[455]

352. The Department also pointed to the fact that MERC exceeded its total firm contracted capacity at Rochester TBS 1D during the Polar Vortex of January 2014.[456]

353. Based on these facts, the Department concluded that the Rochester area is "inadequately served."[457]

3. The OAG's Position

354. The OAG disagreed with MERC and the Department that the Rochester area is an "inadequately served area" within the meaning of the NGEP statute.

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[449] *Id.*, subd. 1(i).
[450] *Id.*, subd. 1(e); Ex. 5 at 18 (Lee Direct).
[451] Minn. Stat. § 216B.1638, subd. 1(i).
[452] Ex. 405 at 59 (Heinen Direct).
[453] Department's Initial Br. at 46 (Oct. 11, 2016) (eDocket No. 201610-125576-01).
[454] Ex. 405 at 38 (Heinen Direct).
[455] *Id.*
[456] Department Reply Br. at 1 (Oct. 25, 2016) (eDocket No. 201610-125979-02).
[457] *Id.* at 1; Department Initial Br. at 46 (Oct. 11, 2016) (eDocket No. 201610-125576-01).

355. The OAG maintained that the statutory phrase is ambiguous and the legislative history supports a different interpretation than that suggested by MERC.

356. The OAG argued that the phase “unserved or inadequately served area” is ambiguous for two reasons.[458] First, the OAG argued that Minnesota law instructs that the Legislature intends technical terms, like “unserved” and “inadequately served” areas, to be read as terms of art.[459] The OAG maintained that these are technical terms with special meanings, and pointed to a publication entitled *Line Extensions for Natural Gas: Regulatory Considerations*, published by the National Regulatory Research Institute (NRRI).[460] The OAG stated that this publication specifies that “unserved areas” means “areas remote from the nearest utility’s gas system.”[461] The OAG also claimed that according to the NRRI article, “inadequately” 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.”[462]

357. The OAG argued that the special meanings given to these technical terms in the NRRI publication are different than the interpretation suggested by MERC. On that basis, the OAG argued that the meaning of the phrase “unserved or inadequately served area” is ambiguous.[463]

358. Second, the OAG asserted that the NGEP statute is ambiguous because accepting MERC’s proposed interpretation would lead to an absurd and unreasonable result.[464] According to the OAG, 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 include the vast majority of natural gas utilities’ projects, rendering them eligible for non-rate case recovery via the NGEP rider. The OAG maintained that such an outcome would present an unprecedented change to the utility regulatory process in Minnesota.[465]

359. Based on its view that the NGEP statute is ambiguous, the OAG looked to the statute’s legislative history to determine the legislature’s intent as to the scope of the phrase "unserved or inadequately served area." The OAG maintained that the legislative history indicates that the legislature intended the NGEP rider to be used “to promote the expansion of natural gas service in Minnesota to communities where it otherwise is uneconomical to extend service.”[466] The OAG argued that the legislative history shows that the NGEP statute was intended to encourage extension of gas service to new customers, not for infrastructure to serve existing customers.[467]

[458] OAG Initial Br. at 80 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
[459] *Id.* at 81.
[460] *Id.*
[461] *Id.*
[462] *Id.* at 82.
[463] *Id.*
[464] *Id.*
[465] *Id.* at 82-83.
[466] *Id.* at 86.
[467] *Id.* at 86-99.

4. Analysis

360. In analyzing whether the Rochester Project is eligible under the NGEP statute, the starting place is the plain language of the statute. When the words of a statute are clear in their application to a particular case, the plain meaning of the law must not be disregarded.[468]

361. Here, the statutory language is clear and unambiguous.

362. The legislature defined the applicable terms. The term "natural gas extension project" means "the construction of new infrastructure or upgrades to existing natural gas facilities necessary to serve currently unserved or inadequately served areas." Further, the legislature expressly provided that "unserved or inadequately served area" means "an area in this state lacking adequate natural gas pipeline infrastructure to meet the demand of existing or potential end-use customers.[469]

363. The Rochester Project clearly fits within these definitions.

364. The Rochester area is an "inadequately served area" because the area lacks **"**adequate natural gas pipeline infrastructure to meet the demand of existing or potential end-use customers."[470] Currently, "in situations of very high demand, MERC's existing low-pressure distribution system in Rochester cannot distribute all of the gas supply available in the southern portion of the system to the northern portion of the system where it is needed."[471] MERC's distribution system is constrained and cannot reliably serve existing and future customers in the Rochester area.[472]

365. In addition, the Project meets the definition of a "natural gas extension project" because the Project will undertake construction of "upgrades to existing natural gas facilities necessary to serve" this "inadequately served area[]."[473]

366. Because the legislature defined these terms and the language is clear as applied to this situation, there is no need to resort to canons of statutory construction or the legislative history.[474]

367. In addition, even if it were appropriate to consider canons of statutory construction, the publication referenced by the OAG does not support the OAG's claim that the term "inadequately served" is a technical term with a special meaning. In fact, the NRRI publication cited by the OAG does not include the phase "inadequately served"

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468 Minn. Stat. § 645.16 (2016); *ILHC of Eagan, LLC v. County of Dakota*, 693 N.W.2d 412, 419 (Minn. 2005).
469 Minn. Stat. § 216.1638, subd. 1(e), (i).
470 Ex. 5 at 10-11, 18 (Lee Direct); Ex. 405 at 38, 59 (Heinen Direct).
471 Ex. 5 at 11 (Lee Direct).
472 Ex. 1 at 2 (Petition); Ex. 12 at 6-7 (Mead); Ex. 5 at 10-11 (Lee); Ex. 405 at 38, 59 (Heinen Direct).
473 Ex. 5 at 10-11, 18 (Lee Direct); Ex. 405 at 38, 59 (Heinen Direct).
474 Minn. Stat. § 645.16 ("When the words of a law in their application to an existing situation are clear and free from all ambiguity, the letter of the law shall not be disregarded under the pretext of pursuing the spirit.")

area.[475] While the article does provide a definition of "underserved" area, the term "underserved" area is not synonymous with "inadequately served" as the definition provided by the legislature demonstrates.

368. Moreover, the OAG's suggestion that the NGEP statute only applies to infrastructure designed to extend service to new customers is contrary to the legislature's express intent. The legislature specifically provided that an "inadequately served area" includes "an area lacking adequate natural gas pipeline infrastructure to meet the demand of *existing* or potential end-use customers."[476] Thus, the legislature expressly included projects, like the Rochester Project, that provide infrastructure to meet the demand of existing customers, as well as future customers.[477]

369. For these reasons, the Administrative Law Judge concludes the Rochester Project is a natural gas extension project which is eligible for recovery of costs through a NGEP rider.

B. Cap on Phase II Project Costs

370. The Department recommended that the Commission establish a soft cap of $44,006,607 for Phase II of the Project.[478] This is the amount that MERC estimates the Phase II upgrades will cost.[479] The Department suggested that MERC would need to establish that any amount above the cap is reasonable.[480]

371. The Department maintained that the Commission should include a cap to ensure that MERC has an incentive to control the costs of the Project.[481]

372. The Department noted that a soft cap is consistent with the Commission's approach regarding cost recovery in prior proceedings.[482] The Department cited to the Commission's recent decision with regard to the Great Northern transmission line as an example, where the Commission adopted a soft cap on rider cost recovery.[483]

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[475] OAG Initial Br. at 81-82 (Oct. 11, 2016) (eDocket No. 201610-125583-01) (citing Ken Costello, Nat'l Regulatory Research Inst., *Line Extensions for Natural Gas: Regulatory Considerations* 3 (Feb. 2013)).
[476] Minn. Stat. § 216B.1638, subd. 1(i).
[477] While there is no need to consult the legislative history for the reasons discussed above, to the extent the Commission disagrees, the Administrative Law Judge notes that there is a letter in the record from Rep. Garofalo dated October 17, 2016, discussing his recollection of the legislature's intent. Rep. Garofalo has a different view of the legislative history than the OAG. *See* Letter from Rep. Pat Garofalo (Oct. 25, 2016) (eDocket No. 201610-125988-02).
[478] Ex. 405 at 43 (Heinen Direct).
[479] Ex. 5 at 16 (Lee Direct).
[480] Ex. 405 at 43 (Heinen Direct).
[481] *Id.* at 41.
[482] *Id.* at 40-43.
[483] Ex. 407 at 8 (Heinen Surrebuttal) (citing *In re Request of Minn. Power for a Certificate of Need for the Great Northern Transmission Line*, MPUC Docket No. E015/CN-12-1163, ORDER GRANTING CERTIFICATE OF NEED WITH CONDITIONS (June 30, 2015)).

373. In addition, the Department asserted that MERC would still bear the burden of proof in future rider filings and general rate case proceedings to show that individual expenditures for Phase II are just and reasonable even with a soft cap.[484]

374. The Department also noted that the $44,006,607 estimate includes a $7,343,321 contingency factor.[485]

375. In Rebuttal Testimony, MERC responded that it disagreed with the Department's view of the review process applicable to the Rochester Project. According to MERC, the NGEP statute contemplates that the Commission will make a determination in this proceeding as to whether the proposed Project and the proposed Project costs are prudent and reasonable. If the Commission agrees that the Project is reasonable and prudent, then the Commission's order "should include a finding that implementing the Project for approximately $44 million is reasonable and prudent."[486] When MERC seeks actual cost recovery in subsequent NGEP rider and rate case filings, "the review should be focused on (i) whether MERC adequately implemented the Project as approved; (ii) whether the costs incurred in furtherance of the Project were within the amount contemplated in the approval; and (iii) whether any cost deviations were justified under the circumstances."[487]

376. In addition, MERC noted that its estimate of $44 million is not a guaranteed price but rather a good-faith estimate of the capital cost of Phase II based on the facts known to MERC at the time the estimate was made. MERC stated that it continues to support the estimate of approximately $44 million, but added that the estimate could change by the time of actual construction.[488]

377. MERC noted the routing of the Phase II pipeline is currently being considered in the companion docket: G011/PR-15-858.[489] Until the final route is determined, it is not possible to fully complete the design to conform the Project to the route. If the final route selected results in more challenging topography or the need to condemn more property than originally planned, cost changes are possible.[490] MERC also noted that it is not able to acquire easements for the Project until the final route is selected. MERC indicated that it could experience higher easement costs than anticipated because many subdivisions are being developed at the end of the proposed route, which could increase land values along the route.[491]

378. For these reasons, in testimony MERC opposed a hard cap but did not oppose a soft cap of approximately $44 million.[492] According to MERC, the estimate of approximately $44 million for Phase II should be considered a baseline against which

[484] Ex. 405 at 43-44 (Heinen Direct).
[485] *Id.* at 43.
[486] Ex. 6 at 27-28 (Lee Rebuttal).
[487] *Id.* at 28.
[488] Ex. 8 at 3 (Lyle Rebuttal).
[489] Ex. 6 at 28 (Lee Rebuttal).
[490] Ex. 8 at 4-5 (Lyle Rebuttal).
[491] *Id.* at 5.
[492] Ex. 6 at 28 (Lee Rebuttal); Tr. Vol. 1 at 44 (Lee).

actual costs would be measured.[493] MERC agreed with the Department that the utility has the burden of proving that any cost changes are reasonable.[494]

379. MERC also asserted that the contingency factor included in the estimate is a standard contingency factor for projects of this type, which MERC considers to be reasonable.[495]

380. After reviewing MERC's Rebuttal Testimony, the Department continued to recommend a soft cap of approximately $44 million.[496] The Department did not take issue with the contingency factor.[497]

381. The Department noted that, with a soft cap, MERC would still have the ability to recover costs above the cap if it can justify the costs.[498]

382. In its Initial Brief, MERC accepted the Department's recommendation that the $44 million estimate for Phase II costs should be treated as a soft cap and that MERC retains the burden of proving that costs in excess of the estimated $44 million are reasonable.[499]

383. Likewise, in its Initial Brief the OAG agreed with the Department's recommendation that the Commission should establish a soft cap if the Rochester Project is approved.[500]

384. The Administrative Law Judge concludes that it is reasonable to apply a soft cap of $44,006,607 to Phase II of the Rochester Project. A soft cap, based on MERC's estimate of its Phase II costs, will provide an incentive for MERC to control its costs. A soft cap will also help ensure that ratepayers do not pay any more than is reasonably necessary for Phase II, either through the NGEP Rider or in base rates, because MERC will have the burden to prove that any excess amounts are prudent and reasonable.

C. NGEP Rider Rate Design

385. As discussed above, MERC has proposed to recover Phase II costs through both through a NGEP rider and through base rates. MERC seeks to recover one-third of its revenue deficiency associated with Phase II through a NGEP rider.[501]

386. If the NGEP rider is approved, MERC proposed to file, by October 1 of each year, the projected rider-eligible revenue deficiency for the upcoming year. MERC's filing would include a flat per-therm rider rate to be effective January 1st of the following year.

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[493] Ex. 6 at 28 (Lee Rebuttal).
[494] *Id.*
[495] Ex. 8 at 6 (Lyle Rebuttal).
[496] Ex. 410 (Heinen Opening Statement).
[497] Ex. 407 at 9 (Heinen Surrebuttal); Ex. 410 (Heinen Opening Statement).
[498] Ex. 407 at 7 (Heinen Surrebuttal).
[499] MERC Initial Br. at 42 (Oct. 11, 2016) (eDocket No. 201610-125589-01).
[500] OAG Initial Br. at 110 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
[501] Ex. 5 at 17 (Lee Direct).

The rider would apply to all of MERC's customers (firm, interruptible, and transportation). The NGEP rider rate would be calculated annually and would include a true-up to correct any previous over- or under-recovery of the Project's rider-eligible revenue deficiency.[502]

387. According to MERC, the estimated increase for the average residential customer from the NGEP rider would range from $0.08 per year ($0.007 per month) in 2017 to approximately $1.56 per year ($0.13 per month) in 2023 if the costs are spread over all customers via a volumetric surcharge as proposed.

388. If the NGEP rider costs are not recovered from all of MERC's customers but instead only customers in the Rochester area, MERC estimated the average residential customer in the Rochester area would see an annual bill impact in the range of approximately $0.55 per year ($0.045 per month) in 2017 to $10.18 per year ($0.85 per month) in 2023.[503]

389. MERC maintained that the allocation of the Phase II costs across all customers using a flat per therm rate is a reasonable approach and is consistent with the NGEP statute, Minn. Stat. § 216B.1638.[504] The NGEP statute specifically requires that any NGEP rider recovery "shall include all of the utility's customers, including transport customers."[505]

1. The Department's Position

390. While the Department did not object to recovery of up to 33 percent of Rochester Project costs though a rider on a flat per therm basis, the Department disagreed with MERC's proposal to recover the NGEP rider costs equally from all customers.[506]

391. The Department recommended instead that MERC's NGEP rider revenue deficiency first be split so that at least 50 percent of the costs recovered from the rider would be charged to all ratepayers in Rochester, with the remaining amounts charged to all ratepayers outside of Rochester.[507] Once this revenue apportionment is made, a flat per therm rider charge could be calculated for Rochester customers and a separate flat per therm charge could be calculated for the non-Rochester customers.[508]

392. The Department recommended that Rochester customers pay more than non-Rochester customers under the NGEP rider because the Rochester Project would most directly benefit Rochester area customers by improving reliability and allowing for additional growth anticipated with the DMC. The Department recognized that customers

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502 *Id.* at 17, n.1.
503 Ex. 5 at 25, ASL-1 (Lee Direct).
504 *Id.* at 26.
505 Minn. Stat. § 216B.1638, subd. 2; Ex. 5 at 25 (Lee Direct).
506 Ex. 400 at 3 (Peirce Direct).
507 *Id.*
508 *Id.* Ms. Peirce noted that the 50/50 split of costs referred to the amount remaining after assignment of costs to RPU, per the testimony of Department witness Mr. Heinen who stated that RPU is planning to build multiple natural gas electricity generators in the future. *Id.* at 4.

outside the Rochester area would also benefit from improved reliability on MERC's system and should share in the costs.[509]

393. The Department recommended the 50/50 split of rider costs as a means to balance the cost recovery between Rochester and non-Rochester customers without overburdening either group. The 50/50 split is not based on a cost calculation by area but rather reflects the Department's judgment of a reasonable allocation of the costs.[510]

394. The tables below, prepared by the Department, summarize the average estimated monthly bill impact by customer class under MERC's proposal and the Department's 50/50 proposal in 2017 and 2020.[511]

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

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

[509] *Id.*
[510] Tr. Vol. 1 at 206 (Peirce).
[511] Ex. 401 at 7-8 (Peirce Surrebuttal).

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

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

2. MERC's Response

395. MERC disagreed with the Department's 50/50 proposal for recovery of Rochester Project costs under the NGEP rider. MERC recognized that the Commission can allocate the costs in the way manner recommended by the Department but asserted that its apportionment of costs is "a more appropriate methodology under all of the circumstances." MERC recommended in favor of its proposal and against the Department's proposal for the following reasons:

- Spreading the costs equally across all customers is consistent with Commission precedent that spreads system upgrade costs across the entire rate base regardless of the location of the specific project or the customers directly served by the project;

- Spreading costs equally across all customers is consistent with the policy underlying the NGEP statute;

- While customers from the Rochester area will benefit from the Project, customers in other locations will also benefit from the Project;

- The Department's proposed 50/50 split would result in different rate zones within the MERC system, which is inconsistent with MERC's efforts to consolidate its operating companies and PGAs;

- Allocating 50 percent of Project costs to Rochester area customers imposes a potentially excessive cost burden on those customers; and

- Having a higher rider rate for Rochester customers than other customers would require MERC to maintain two separate tariffs and two separate sets of accounting books.[512]

396. MERC noted that when the Rochester Project is completed, the conditions of service in the Rochester area will be the same as conditions of service offered to comparable MERC customers elsewhere in MERC's service territory: "namely, all customers will have the opportunity to secure firm and reliable natural gas service." According to MERC, the customers in and around Rochester are not receiving a windfall or a benefit in comparison to other customers. Rather, MERC is working to upgrade its system so that customers within and around Rochester continue to receive the same reliable service as MERC customers in other parts of the state.[513]

3. The Department's Surrebuttal

397. In Surrebuttal Testimony, the Department continued to recommend that at least 50 percent of the Project revenue deficiency be apportioned to MERC's Rochester customers.[514] The Department recognized that the NGEP statute requires recovery of NGEP costs from all customers of the utility, but noted that it does not require that the rates be the same for all customers. Rather, the statute contemplates that a utility could propose to apportion the revenue deficiency among its customer classes on a basis of its choosing.[515]

398. With respect to MERC's concern that the Department's proposed methodology would result in a functionally separate rate zone for Rochester, the Department noted that the NGEP rider reflects only one-third of the Project's costs and will be a separate line item on customer bills. The Department also asserted that at some point the Company will file to include the Rochester Project in base rates, and the Commission and parties are free to revisit the appropriate apportionment of costs among MERC's customers at that time. The Department stated that it did not expect the rate

[512] Ex. 6 at 10-17 (Lee Rebuttal); Ex. 24 (Lee Opening Statement).
[513] Ex. 6 at 15 (Lee Rebuttal).
[514] Ex. 401 at 8-9 (Peirce Surrebuttal); Ex. 408 (Peirce Opening Statement).
[515] Ex. 401 at 2-3 (Peirce Surrebuttal) (citing Minn. Stat. § 216B.1638, subd. 2(a)).

differentials proposed between Rochester and non-Rochester customers will result in a long-term separate rate zone.[516]

399. The Department also reiterated that Rochester area customers would benefit most directly from the Rochester Project and therefore it is reasonable that those customers pay a greater portion of the costs.[517]

4. The OAG's Position

400. In testimony, the OAG stated that it does not oppose MERC's proposal to allocate the Phase II costs across all customers, but is open to discussion of alternative solutions.[518]

401. In its Initial Brief, the OAG recommended that if the Commission approves the Project, the Commission should approve MERC's proposal for cost recovery of Phase II costs. The OAG noted that MERC's proposal is consistent with the general policy in Minnesota to spread system upgrade costs among all customers.[519]

5. Analysis

402. The Administrative Law Judge concludes that MERC's proposed rate design for the NGEP rider is the most reasonable approach.

403. While the Administrative Law Judge understands the Department's reasons for recommending that Rochester customers pay a greater share than other MERC customers, such an approach is not consistent with past practice.[520]

404. In addition, such an approach could lead to multiple location-specific rates across MERC's territory if additional NGEP projects are proposed in the future.

405. A wide variation in rates for customers of the same class based on location alone could cause customer confusion, increase billing costs, and have other unintended consequences.

406. For these reasons, the Administrative Law Judge recommends that the Commission approve MERC's proposed rate design for recovery of Rochester Project Phase II costs through a flat per therm rate applicable to all ratepayers.

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[516] *Id.* at 3-4.
[517] *Id.* at 4.
[518] Ex. 300 at 60 (Urban Amended and Corrected Direct).
[519] OAG Initial Br. at 100-101, 112 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
[520] Tr. Vol. 1 at 207-208 (Peirce).

D. Recovery of NNG Capacity Costs

407. As discussed above in paragraphs 226-231, MERC has entered into a PA with NNG for increased interstate capacity to address capacity issues in the Rochester area.[521]

408. Under the PA, NNG's costs to provide additional interstate pipeline capacity to the Rochester area will be paid through monthly capacity payments over a 25-year period, with an option to extend the capacity contract another five years at a significantly discounted rate per Dekatherm.[522]

1. MERC's Proposal

409. MERC has proposed to recover the approximately $60 million in additional capacity costs from all of its customers on the NNG PGA.[523] MERC would recover the capacity costs through the commodity portion of the PGA, which is paid both by both firm sales customers (Residential, Small C&I, and Large C&I) and by interruptible customers.[524]

410. MERC is not proposing to recover any of the NNG PGA costs from its transportation customers because these customers do not purchase gas or interstate delivery service from MERC. Instead, they arrange for their own interstate gas transportation.[525] The only service that transportation customers purchase from MERC is local distribution service on the MERC system.[526] MERC noted that transportation customers will be paying for their share of improvements to MERC's distribution system, from which they directly benefit.[527]

411. According to MERC, it is reasonable that all non-transportation customers in the NNG PGA area pay for the additional interstate capacity because the terms of the PA provide benefits to all MERC customers in the NNG PGA area. As discussed above, MERC's PA allows MERC to use the additional capacity not only in the Rochester area but also in 21 neighboring communities.[528] Moreover, all customers would benefit from access to future capacity expansions at competitive rates, increased operability and reliability of service, and the ability of future load growth in a timely manner.[529]

412. For these reasons, MERC asserted that allocation of costs across the entire NNG PGA area, not just the Rochester area, is appropriate. MERC noted that this

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[521] Ex. 5 at 12-13 (Lee Direct).
[522] *Id.* at 17.
[523] Ex. 5 at 16 (Lee Direct); Ex. 6 at 19-20 (Lee Rebuttal).
[524] Ex. 6 at 24 (Lee Rebuttal); Ex. 24 at 2 (Lee Opening Statement).
[525] Ex. 5 at 30 (Lee Direct); Ex. 6 at 18-20 (Lee Rebuttal).
[526] *See* Ex. 5 at 30 (Lee Direct).
[527] *Id.*
[528] *Id.* at 28.
[529] *Id.* at 29.

treatment is consistent with prior practice where an interstate capacity contract has system-wide benefits.[530]

413. MERC estimated that the rate increase for the average residential customer on the NNG PGA for recovery of the PA costs would range from $2.48 in 2018 to $28.42 in 2020, reducing thereafter to the $28.25 to $27.17 per year range.[531] If recovery is limited to customers in Rochester only, there would also be about a four-fold increase. The estimated increase to the NNG PGA for the average residential customer in Rochester would be in the range of $10.99 in 2018 to $124.96 in 2020, reducing thereafter to a range of $120.92 to $114.70.[532]

414. In MERC's view, collecting the NNG costs from Rochester customers only would place an undue burden on Rochester customers and result in Rochester customers subsidizing other customers in the NNG PGA area, who also receive benefits from the increased capacity.[533]

2. The Department's Position

415. The Department supported recovery of the increased NNG capacity costs through MERC's NNG PGA from both firm and interruptible customers across the entire NNG PGA.[534] The Department agreed that both firm and interruptible customers should pay for the costs of the additional capacity on the NNG system because expansion of NNG's capacity affects all of MERC ratepayers. The Department noted that more than firm customers benefit from the increased capacity. Interruptible customers also benefit because expansion of the NNG system makes it less likely that interruptible customers will be curtailed.[535]

416. With respect to transportation customers, the Department recognized that these customers do not purchase gas or interstate transport service from MERC and therefore the Department did not envision that transportation customers would incur MERC's capacity costs passed on through the NNG PGA.[536] The Department noted that transportation customers will pay for the Rochester Project to the extent that they purchase capacity on the NNG system when MERC sells excess capacity on the capacity release market.[537]

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530 *Id.* at 27, 29.
531 Ex. 304, JAU-30 at 3 (Urban Direct Schedules) (MERC response to OAG IR No. 171).
532 *Id.*
533 Ex. 5 at 34 (Lee Direct).
534 Ex. 401 at 9 (Peirce Surrebuttal); Ex. 407 at 10 (Heinen Surrebuttal).
535 Ex. 405 at 50 (Heinen Direct).
536 Ex. 407 at 10 (Heinen Surrebuttal). As noted above, the Department did recommend that all customers, including transport customers, be responsible for Phase II costs recovered through the NGEP rider.
537 *Id.* at 13.

417. MERC currently provides information on capacity release in its Annual Automatic Adjustment (AAA) filings. Generally, these data are reported on a system-wide basis.[538]

418. To ensure that MERC's firm and interruptible customers receive appropriate benefit from capacity release to transportation customers, the Department recommended that MERC provide specific data for capacity releases associated with the Rochester area in future AAA filings, and in the annual rider recovery filing.[539] At the evidentiary hearing, MERC agreed to this recommendation.[540]

3. The OAG's Position

419. The OAG agreed that the cost for the NNG upgrades should be spread across the NNG PGA rather than just the Rochester customers.[541] The OAG recognized that the PA provides capacity benefits not just for Rochester but for MERC's customers throughout southeastern Minnesota. In addition, the OAG agreed that allocating costs solely to Rochester customers would be significant and burdensome.[542]

420. The OAG also agreed with the Department that recovery of increased NNG costs should not be limited to firm customers because interruptible and transportation customers will also benefit indirectly from the increased capacity.[543] The OAG recommended that the increased NNG costs be recovered from firm, interruptible and transportation customers because they will all benefit from the increased capacity.[544]

421. The OAG asserted that transportation customers will receive benefits from the newly available NNG capacity if the Rochester Project is built even though they do not purchase gas or capacity on the NNG system from MERC.[545] The new capacity of the NNG system will represent capacity that is available to transportation customers on the capacity release market on days that MERC is not utilizing all of the available capacity. The increased capacity may also make it easier for transportation customers to negotiate more favorable contract terms for capacity.[546] According to the OAG, the amount of excess supply on the system may reduce prices in the capacity market.[547] The OAG raised concerns about transportation customers sharing in the benefits of the new

[538] *Id.* at 13-14.
[539] *Id.*
[540] Tr. Vol. 1 at 20 (Lee).
[541] Ex. 300 at 61 (Urban Amended and Corrected Direct).
[542] *Id.* at 61-62.
[543] Ex. 300 at 63 (Urban Amended and Corrected Direct); Ex. 308 at 19 (Urban Amended and Corrected Rebuttal).
[544] Ex. 300 at 63 (Urban Amended and Corrected Direct); Ex. 308 at 19 (Urban Amended and Corrected Rebuttal).
[545] OAG Initial Br. at 106-07 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
[546] *Id.* at 106; Ex. 405 at 47 (Heinen Direct); Ex. 5 at 28 (Lee Direct).
[547] OAG Initial Br. at 107-08 (Oct. 11, 2016) (eDocket No. 201610-125583-01).

capacity but not sharing in the costs, except to the extent they purchase excess capacity on the capacity market.[548]

422. The OAG recommended that transportation customers be allocated a portion of the NNG PA costs in addition to firm and interruptible customers, but did not provide a specific recommendation. Instead, the OAG recommended that if the Project is approved, the Company should be ordered to work with the parties to ensure the burden does not fall unfairly on MERC's firm customers.[549]

4. SLGI's Position

423. While SLGI did not submit testimony during this proceeding, in its Initial Post-Hearing Brief SLGI agreed with MERC's proposal to recover the NNG costs from firm and interruptible customers through MERC's PGA.[550]

424. SGLI maintained that it would be unreasonable for MERC to charge its transportation customers for the NNG capacity upgrades because transportation customers do not purchase either natural gas commodity or interstate pipeline capacity from MERC. SLGI also asserted that if the Company were to directly charge transportation customers for the NNG capacity upgrade, those customers would be charged twice for capacity.[551]

425. SLGI emphasized that transportation customers will not have access to the additional capacity purchased by MERC from NNG except through possible future capacity releases.[552]

426. SLGI noted that very large transportation customers will bear a significant portion of the Phase II costs if MERC's proposal to impose a per therm charge is approved because those customers consume a significant portion of MERC's total distribution throughput.[553] As a result, SLGI maintained that very large transportation customers will pay their fair share of costs from the Project.[554]

5. Analysis

427. The Administrative Law Judges finds that MERC's proposal to recover the costs of the NNG upgrades from both firm and interruptible system sales customers through the commodity portion of the NNG PGA is reasonable and supported by the record.

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548 *Id.* at 108.
549 Ex. 300 at 63 (Urban Direct); Ex. 307 at 19 (Urban Rebuttal); OAG Initial Br. at 109 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
550 SLGI Initial Br. at 3 (Oct. 11, 2016) (eDocket No. 201610-125592-02).
551 *Id.* at 3-4.
552 *Id.* at 3.
553 *Id.* at 4.
554 *Id.* at 4.

428. The Administrative Law Judge concludes that transportation customers will pay for the NNG upgrade costs to the extent that they purchase capacity on the NNG system when MERC sells capacity on the capacity release market.

429. Because transportation customers will not have the right to use any of the additional capacity on the NNG system acquired by MERC, except to the extent purchased on the capacity release market, the Administrative Law Judge finds it would be unreasonable to directly charge transportation customers for the NNG capacity acquired through the PA.

430. The Administrative Law Judge recognizes the OAG's concerns regarding transportation customers benefiting from the additional capacity. Requiring MERC to actively seek long-term buyers for near term excess capacity and also requiring MERC to actively sell short-term excess capacity on the capacity release market, as recommended by the Department, will address some of these concerns.[555]

431. The Administrative Law Judge finds that it is reasonable to require MERC to provide specific data for each capacity release associated with the Rochester area in future AAA filings, and in the annual rider recovery filing in this docket.

XI. Adjustments to Interruptible Rates and Transportation Rates

432. If the Rochester Project is approved, parties suggested that the Commission consider adjusting MERC's interruptible rates and transportation rates.

433. Interruptible customers receive a discount to their distribution rates because of their agreement to curtail consumption when called upon to do so.[556] As described by Department witness 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".[557]

434. 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.[558] 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.[559] For the benefit they provide to the system, namely their agreement to have their gas supplies curtailed when necessary, the interruptible customers receive significant rate discounts.

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[555] While the Commission could require the parties to have further discussions about this issue as recommended by the OAG, the OAG has not provided any specific proposals for further recovery of NNG costs from transportation customers.
[556] Ex. 300 at 63 (Urban Amended and Corrected Direct).
[557] Ex. 405 at 9 (Heinen Direct).
[558] OAG Initial Br. at 104 (citing MERC Energy Resources Corporation Tariff Book, 4th Revised Sheet No. 5.00).
[559] *Id.* (citing 4th Revised Sheet Nos. 5.21 & 5.21).

435. The OAG raised concerns about the reasonableness of MERC's interruptible discounts given the amount of capacity to be added by the Rochester Project. In the OAG's view, the additional capacity would mean that interruptible customers would have essentially no risk of curtailment.[560]

436. The OAG also asserted that the additional capacity will provide an incentive for large customers and others who qualify to switch to interruptible service because the risk of curtailment will be very low.[561] If customers switch from firm service to interruptible service, the cost burden on the remaining firm customers will increase.[562]

437. The OAG argued that if the Rochester Project goes forward as proposed, interruptible customers would not be providing any real benefit to the system because there would be so much excess capacity. As a result, the OAG questioned whether interruptible customers should continue to receive the same discount.[563]

438. The OAG requested that MERC provide information about recalculating the interruptible discount if the Project is approved.[564] MERC declined to provide a detailed discussion, but did agree to review its tariffs to ensure that interruptible customers are not allowed a "free ride."[565]

439. Like the OAG, the Department recommended that the Company address interruptible rates in its next general rate case. The Department also raised concerns about transportation rates. The Department recommended that MERC provide a detailed analysis in its next general rate case of the reasonableness of MERC's current interruptible and transportation rates, as well as a discussion of "whether the rate structures and design for these classes are appropriate given the impacts (*e.g.*, excess firm capacity, less chance of curtailment) associated with the [] Project."[566]

440. In Rebuttal Testimony, MERC acknowledged that the Rochester Project would make curtailment less likely in the near-term. MERC noted that the Project would not eliminate the risk of interruption as a result of force majeure events, distribution constraints, or even gas supply constraints.[567]

441. At the evidentiary hearing, MERC agreed to provide an analysis of its interruptible rates and transportation rates in its next rate case. MERC also agreed to address whether the rate structures and design for these classes are appropriate given impacts associated with the Project.[568]

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560 Ex. 300 at 63 (Urban Amended and Corrected Direct).
561 *Id.*
562 OAG Initial Br. at 105 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
563 Ex. 300 at 63 (Urban Amended and Corrected Direct); OAG Initial Br. at 105 (Oct. 11, 2016) (eDocket No. 201610-125583-01).
564 Ex. 300 at 63 (Urban Amended and Corrected Direct).
565 Ex. 6 at 44 (Lee Rebuttal).
566 Ex. 407 at 14 (Heinen Surrebuttal).
567 Ex. 6 at 40 (Lee Rebuttal).
568 Ex. 24 at 3 (Lee Opening Statement); Tr. Vol. 1 at 20 (Lee).

442. The Administrative Law Judge concludes the current interruptible and transportation rates should be reexamined if the Project is approved to ensure that the rates are appropriate, given the reduced risk of curtailment that is likely to result from the Project.

XII. Other Potential Funding Sources

443. The NGEP statute, Minn. Stat. § 216B.1638, requires the utility to include a description of efforts made by the utility to offset the revenue deficiency for project through contributions in aid of construction.[569]

444. In addition, in its Notice and Order for Hearing the Commission requested that the scope of the hearing include an examination of "[w]hat other funds may be available to cover the project costs."[570]

445. As discussed below, MERC and the parties examined whether contribution in aid of construction (CIAC) or other potential sources of funding would be available to cover a portion of the Project costs.

A. CIAC

446. CIAC can be a source of funding for a project undertaken to extend service to a particular customer or customer group. If a new line extension for a particular customer is not a net revenue generator over the course of the line's life, MERC recovers the deficiency from the new customer through a CIAC.[571]

447. Similarly, natural gas extensions that involve the construction of distribution infrastructure to provide service in an area that a utility has not previously served may be financed through a New Area Surcharge (NAS). This enables the utility to extend service into a new area that would be uneconomic to serve at tariffed rates by permitting the utility to collect a surcharge in addition to its tariffed rates. The NAS feasibility model determines the CIAC amount necessary to reduce a new area project's capital costs to a level that the revenues generated from the new area customers paying the utility's tariffed rates will recover the new area project's projected revenue requirements. The CIAC amount is recovered from the new area customers through a NAS.[572]

448. Because the Rochester Project is a system integrity project and is not designed to extend service to specific new customers, MERC does not anticipate receiving any CIAC revenues to offset any portion of the Rochester Project costs.[573]

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[569] Minn. Stat. § 216B.1638, subd. 2(b)(4).
[570] NOTICE AND ORDER FOR HEARING at 5 (eDocket No. 20162-118054-01).
[571] Ex. 5 at 20-21 (Lee Direct).
[572] Ex. 5 at 21 (Lee Direct).
[573] *Id.* at 24, 35. The OAG asserted that the Rochester Project makes it "extremely unlikely that any new customer would be required to contribute to obtaining new capacity, even if their needs are extremely large, because MERC proposes to acquire that capacity before it is requested by a potential new customer." According to the OAG, this is another ground for finding the Project unreasonable. OAG Reply Br. at 32-33 (Oct. 25, 2016) (eDocket No. 201610-125991-01).

Similarly, because the Rochester Project is not designed to serve a new area, but rather is being constructed to serve existing and future customers in an area that MERC already serves, MERC's NAS will not be a source of funding for the Project.[574]

B. Destination Medical Center Corporation Funding

449. As noted above, the Mayo Clinic and other community members in the Rochester area seek to develop Rochester into the world's premier DMC. [575] In 2013, the legislature enacted Minn. Stat. §§ 469.40-.47 to aid in the development of the DMC and to create various state and local funding streams to facilitate its implementation.[576]

450. The Destination Medical Center Corporation (DMCC) is a nonprofit corporation created pursuant to Minn. Stat. § 469.41. The DMCC's mission is to prepare and implement a development plan for the DMC.[577] The DMCC is also charged with reviewing proposed projects for consistency with the DMC's development plan for possible government funding.[578]

451. Pursuant to Minn. Stat. § 469.47, state infrastructure aid becomes available to the City of Rochester for DMC public infrastructure projects once $200 million of qualified private investment has been made and the City enters into an agreement with the state to make a qualifying local matching contribution. As of the time of the hearing in this matter, the DMC initiative had not yet reached the $200 million of private investment required to trigger the availability of state infrastructure aid for the DMC. As of April 1, 2016, about $150 million of private funds had been invested.[579]

452. While public funding is not yet available for DMC public infrastructure projects, the DMCC and the City are accepting applications for future funding.[580] Pursuant to Minn. Stat. § 469.47, subd. 3(b), the state infrastructure aid must be used by the City only for "public infrastructure project[s]" approved or adopted by the DMCC.[581] In order for a "public infrastructure project" to be approved, the project must be undertaken as part of the DMC development plan and be located within a DMC development district.[582]

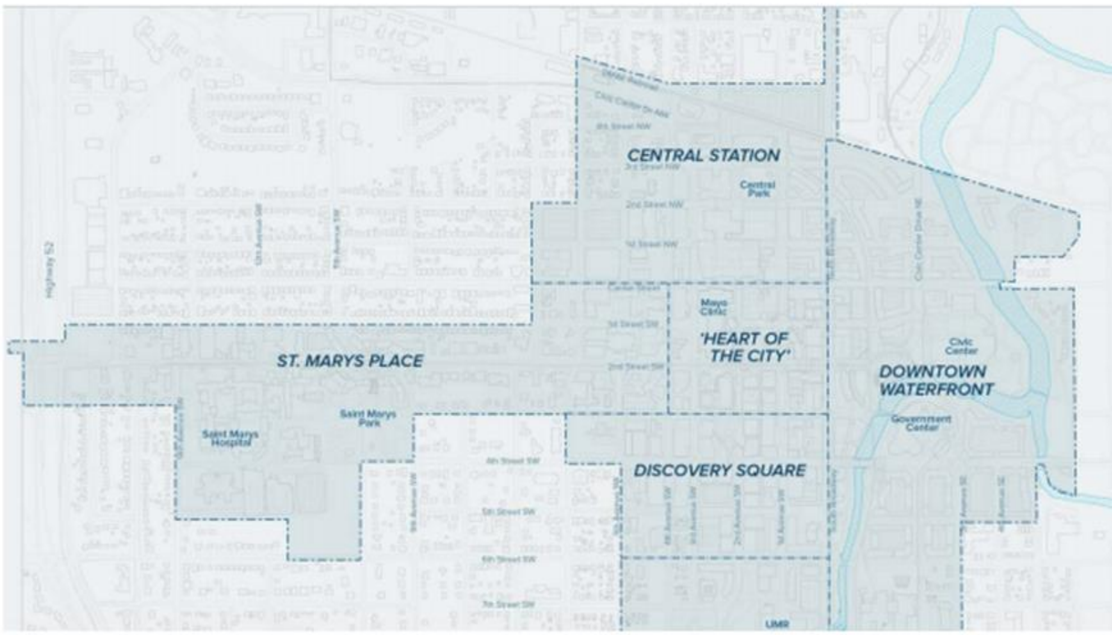
453. Minn. Stat. § 469.40 defines "public infrastructure project" as "a project financed in part or in whole with public money in order to support the medical business entity's development plans, as identified in the DMCC development plan."[583] Under the statute, a "public infrastructure project may . . . install, construct, or reconstruct elements

[574] Ex. 5 at 24, 35 (Lee Direct).
[575] *Id.* at 36; Ex. 405 at 51 (Heinen Direct).
[576] Ex. 405 at 51 (Heinen Direct); 2013 Minn. Laws ch. 143, art. 10, §§ 3-10 at 155-167.
[577] Minn. Stat. § 469.41, subd. 1; Ex. 405 at 51 (Heinen Direct).
[578] Minn. Stat. § 469.41, subd. 13.
[579] Ex. 5 at 37, ASL-2 (Lee Direct); *see also* Minn. Stat. § 469.47.
[580] Ex. 5 at 37 (Lee Direct).
[581] Minn. Stat. § 469.47, subd. 3.
[582] Ex. 6, ALS-R3 (Letter from City of Rochester and DMC Economic Development Agency to MERC dated July 18, 2016).
[583] Minn. Stat. § 469.40, subd. 11(a).

of public infrastructure required to support the overall development of the destination medical center development district including, but not limited to, . . . utilities systems and related facilities [and] utility relocations and replacements."[584]

454. Minn. Stat. § 469.40 also specifies that a DMC development district is a "geographic area in the city identified in the DMCC development plan in which public infrastructure projects are implemented."[585]

455. The current DMCC development plan defines the boundaries of the development district.[586] The below map outlines the general location of the current DMC development district and subdistricts:



456. The district, as currently defined, is generally located in the downtown area in Rochester, in and around the Mayo Clinic.[587]

457. On April 15, 2016, MERC submitted an application to the DMCC seeking $5 million of funding for the Rochester Project from the DMCC and the City of Rochester. The application requested funds to offset Project construction costs.[588]

458. In its application, MERC noted that its Rochester Project is not explicitly included in the DMC Development Plan. MERC also recognized that most of the proposed Project facilities will not be located within the DMC development district

[584] *Id.*, subd. 11(a)(4).
[585] *Id.*, subd. 5.
[586] Ex. 405 at 54-55 (Heinen Direct).
[587] Ex. 405 at 55 (Heinen Direct).
[588] Ex. 5 at 37, ASL-3 (Lee Direct).

boundaries.[589] MERC noted that while the Phase I work was inside the City of Rochester, it generally was not located within the DMC development district. Phase II would also be outside of the development district boundaries but is expressly designed to benefit Rochester.[590] MERC requested that the DMCC amend the Development Plan to the extent necessary to allow funding of the Rochester Project by the DMCC and the City of Rochester.[591]

459. On May 18, 2016, representatives of MERC met with DMC representatives in Rochester to discuss MERC's application.[592]

460. On July 18, 2016, the DMC Economic Development Agency and the City of Rochester sent a letter to MERC in response to MERC's application for funding. The letter notified MERC that MERC is not eligible for DMC funding because the Project does not fall within the development district boundaries.[593]

461. The Department recognized that the Rochester Project will not be built within the DMC development district, and therefore would not be eligible for funding.[594] To the extent MERC undertakes additional projects within a DMC development district, the Department recommended that MERC petition the DMC for funding. The Department also recommended that MERC, in its annual rider filing, include a discussion and supporting data detailing: any and all utility work done throughout the previous year within a DMC development district; the number of applications made to the DMCC; and the amount of state aid received.[595]

462. In its Reply Brief, the OAG expressed concern that MERC had not taken all the steps it could have to try to secure DMC funding.[596] The OAG pointed out that there are provisions in the DMC Plan that would allow the DMCC to amend the Development District boundaries to include a new area.[597] The OAG maintained that if MERC believes that the Rochester Project is necessary for the success of the DMC development plan, then MERC should have provided a thorough and detailed request for amendment to the DMC governing organizations.[598] The OAG also argued that if MERC had engaged earlier with the DMC organizations, the DMC district boundaries might have been designed to include the Project area.[599] The OAG questioned whether MERC has a financial interest in obtaining alternate funding because such funding could impact the amount of investments on which the Company earns a rate of return in the future.[600]

[589] *Id.*, ASL-3 (Lee Direct); *see also* Ex. 405 at 55 (Heinen Direct).
[590] Ex. 5, ASL-3 (Lee Direct).
[591] *Id.*, ASL-3 (Lee Direct).
[592] Ex. 6 at 33 (Lee Rebuttal).
[593] Ex. 6 at 33, ASL-R3 (Lee Rebuttal).
[594] Ex. 405 at 57 (Heinen Direct).
[595] OAG Reply Br. at 30 (Oct. 25, 2016) (eDocket No. 201610-125991-01).
[596] *Id.* at 29-31.
[597] Ex. 300 at 68 (Urban Amended and Corrected Direct).
[598] OAG Reply Br. at 29-30 (Oct. 25, 2016) (eDocket No. 201610-125991-01).
[599] *Id.* at 30-31.
[600] Ex. 300 at 68 (Urban Amended and Corrected Direct).

463. In Rebuttal Testimony, MERC agreed with the Department's recommendation that it pursue DMC funding for future distribution projects that are located with the DMC development district. MERC expected that this effort would result in a series of fairly small DMC funding requests to support costs associated with specific development projects located with the DMC development district.[601]

464. MERC disagreed with the OAG's criticisms regarding MERC's pursuit of DMC funding. MERC asserted that the Company diligently pursued DMC funding. Though its efforts were ultimately unsuccessful, the Company stated that this was not due to a lack of effort. According to MERC, its efforts were unsuccessful because the design of the DMC plan does not support funding a project like the Rochester Project.[602]

C. Other Funding Sources

465. No party proposed any other non-traditional funding source for the Rochester Project.

D. Analysis

466. At this time, there do not appear to be any funding sources other than base rates, the NGEP rider, and the PGA to cover the costs of the Rochester Project. MERC should be encouraged to continue to seek funding from the DMCC in the future.

XIII. Other Findings

467. Any Findings of Fact more properly designated as Conclusions of Law are hereby adopted as such.

Based upon these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. §§ 14.50, 216B.01, 216B.08, 216B.1638 (2016).

2. The parties and the public received proper and timely notice of the hearings in this matter.

3. MERC is a "public utility" as defined by Minn. Stat. § 216B.02, subd. 4 (2016), because it operates facilities for furnishing retail natural gas to the public in Minnesota.[603]

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601 Ex. 6 at 34 (Lee Rebuttal).
602 *Id.*
603 *See* Minn. Stat. § 216B.02, subd. 4.

4. Public utilities are required by Minn. Stat. § 216B.03-.04 to charge "just and reasonable rates" and provide "safe, adequate, efficient, and reasonable service."

5. Minn. Stat. § 216B.1638 allows a public utility to petition the Commission for an advance determination of prudence of a "natural gas extension project" and to request recovery of up to 33 percent of the costs of the project through a rider.[604]

6. A "natural gas extension project" is defined as "the construction of new infrastructure or upgrades to existing natural gas facilities necessary to serve currently unserved or inadequately served areas."[605] The phrase "unserved or inadequately served area" means "an area in this state lacking adequate natural gas pipeline infrastructure to meet the demand of existing or potential end-use customers."[606]

7. Pursuant to Minn. Stat. § 216B.1638, the Commission "shall approve a public utility's petition for a rider to recover the costs of a natural gas extension project if it determines that (1) the project is designed to extend natural gas service to an unserved or inadequately served area; and (2) project costs are reasonably and prudently incurred."[607]

8. MERC has the burden of proof to show that the Rochester Project is necessary, reasonable, and prudent, and to demonstrate that the Project meets the requirements for cost recovery through a NGEP rider.[608]

9. MERC has demonstrated by a preponderance of the evidence that the Rochester Project is necessary, reasonable, and prudent.

10. MERC has shown by a preponderance of the evidence that the Rochester Project is a natural gas extension project within the meaning of Minn. Stat. § 216B.1638.

11. MERC has demonstrated by a preponderance of the evidence that the Rochester Project meets the requirements for authorization of a NGEP rider for recovery of up to 33 percent of Project costs pursuant to Minn. Stat. § 216B.1638. MERC's

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[604] Minn. Stat. § 216B.1638, subds 2-3.
[605] *Id.*, subd. 1(e).
[606] *Id.*, subd. 1(i).
[607] Minn. Stat. § 216B.1638, subd. 3(b)(1)-(2).
[608] Minn. R. 1400.7300; *see also In re Commission Investigation into Xcel Energy's Monticello Life-Cycle Management/Extended Power Uprate Project and Request for Recovery of Cost Overruns*, MPUC Docket No. E-002/CI-13-754, ORDER FINDING IMPRUDENCE, DENYING RETURN ON COST OVERRUNS, AND ESTABLISHING LCM/EPU ALLOCATION FOR RATEMAKING PURPOSES at 12-13 (May 8, 2015). In its Initial Brief, MERC suggested that it should have the initial burden of proof to demonstrate that the Rochester Project is a reasonable and prudent way to satisfy the articulated need, and then the burden should switch to the other parties to show another alternative in record is more reasonable and prudent. MERC noted that Certificate of Need Rules 7851.0110-.0120 (2015) include a similar standard. Because this is not a Certificate of Need proceeding, the Administrative Law Judge concludes it is not proper to apply the Certificate of Need rules to the burden of proof in this proceeding.

recovery of its expenses for Phase II of the Project are properly subject to a soft cap of approximately $44 million.

12. MERC's proposal for cost recovery of up to 33 percent of Phase II through the NGEP rider from all customers is reasonable.

13. MERC's proposal for recovery of the additional NNG costs through its NNG PGA is reasonable.

14. Any Conclusions of Law more properly designated as Findings of Fact are hereby adopted as such.

RECOMMENDATIONS

Based upon the Findings of Fact and Conclusions of Law, the Administrative Law Judge recommends that the Commission issue an order:

1. Finding the Rochester area is constrained and MERC's Rochester Project is prudent, reasonable, and necessary to provide natural gas service to MERC's Rochester service area.

2. Authorizing rider recovery of up to 33 percent of the Phase II costs pursuant to the NGEP statute from all of MERC's customers.

3. Limiting total recovery of Phase II costs to MERC's estimate of $44,006,607, unless MERC can show that any costs above the initial estimate are due to unforeseen or extraordinary circumstances and the additional costs are otherwise reasonable and prudent.

4. Authorizing recovery of the costs incurred under the PA for additional capacity through the commodity portion of the NNG PGA from all of MERC's firm and interruptible system sales customers.

5. Requiring MERC to reasonably pursue mitigation of costs for sales customers including, but not limited to: making every effort to obtain the best available terms for long-term and short-term release of excess capacity; encouraging the movement of customers to firm service; and utilizing excess capacity to avoid purchasing other more expensive capacity to serve other parts of the MERC-NNG PGA.

6. Requiring MERC to provide, in future AAA filings and in the annual rider recovery filing in this docket, specific data for each capacity release associated with the Rochester area over the most recent gas year.

7. Requiring MERC to petition the DMCC for state infrastructure aid if future work by the Company occurs within the development district, and report annually on the results of any applications made to the DMCC and the amount of any state aid received.

8. Requiring MERC to provide a detailed analysis in its next general rate case regarding its existing interruptible and transportation rates and whether the rate structures and design for these classes are appropriate given the increased capacity associated with the proposed Project.

Dated: November 30, 2016

JEANNE M. COCHRAN
Administrative Law Judge

NOTICE

Notice is hereby given that exceptions to this Report, if any, by any party adversely affected must be filed under the time frames established in the Commission's rules of practice and procedure, Minn. R. 7829.2700, .3100 (2015), unless otherwise directed by the Commission. Exceptions should be specific and stated and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Minn. R. 7829.2700, subp. 3. The Commission will make the final determination of the matter after the expiration of the period for filing exceptions, or after oral argument, if an oral argument is held.

The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations. The recommendations of the Administrative Law Judge have no legal effect unless expressly adopted by the Commission as its final order.

OAH 68-2500-33191
MPUC G-011/M-15-895

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of a Petition by Minnesota Energy Resources Corporation for Evaluation and Approval of Rider Recovery for its Rochester Natural Gas Extension Project	**ATTACHMENT A** **SUMMARY OF PUBLIC COMMENT**

Public Hearings

1. The Commission directed the Administrative Law Judge to hold public hearings for this matter "in Rochester and other locations in MERC's service area."[609] Five public hearings were held in July, 2016, in MERC's service area. The public hearings took place in Rochester, Albert Lea, Rosemount, and Cloquet, all in Minnesota.

A. Rochester Public Hearings

2. Two public hearings were held on July 12, 2016, at the Kahler Apache Hotel, 1517 16th Street SW, in Rochester. The first public hearing commenced at 1:00 p.m. and the second public hearing commenced at 6:00 p.m.

3. Rory Lenton, External Affairs Leader, Amber Lee, Regulatory Services Manager, and Lindsay Lyle, Engineering Manager, attended the Rochester public hearings on behalf of MERC. Ryan Barlow, Assistant Attorney General, attended the Rochester public hearings on behalf of the OAG. Susan Peirce, rates analyst, attended the Rochester public hearings on behalf of the Department. Bob Brill, financial analyst, attended the Rochester public hearings on behalf of the Commission.

4. Several presentations were made at the outset of the Rochester public hearing commencing at 1:00 p.m. First, Rory Lenton presented information on MERC and the Project.[610] Second, Susan Peirce provided information on the Department's involvement in the process.[611] Third, Ryan Barlow provided information on the OAG's

[609] NOTICE AND ORDER FOR HEARING at 8 (Feb. 8, 2016) (eDocket No. 20162-118054-01).
[610] Rochester 1:00 p.m. Public Hearing Transcript (Rochester 1:00 p.m. Tr.) at 12-20 (July 12, 2016).
[611] *Id.* at 20-22.

position on the Project.[612] Last, Bob Brill provided information on the Commission's process for reviewing and approving MERC's request in this matter.[613]

5. Seven members of the public attended the afternoon public hearing in Rochester, and one member of the public attended the evening public hearing in Rochester.[614]

6. All members of the public were afforded a full opportunity to make a statement on the record and/or to ask questions.

7. Members of the public asked a number of questions during the first public hearing. One individual asked questions regarding the safety of the expansion Project, including whether there is the possibility of a pipeline emergency and if an odor additive will be used in the natural gas.[615] Another individual asked questions regarding the customer groups necessitating the expansion, including whether more large commercial customers are anticipated than other customer groups.[616] A third individual asked questions regarding the timeframe for the Project and how long customers would be paying for costs and fees associated with the Project.[617] A fourth member of the public asked questions regarding where the record of information from the public hearings can be found.[618] Finally, a fifth member of the public asked questions about from where the natural gas will be sourced.[619]

8. Several individuals also provided comments about the Project during the first public hearing. A few individuals raised concerns about the fairness of requiring current customers to pay for expansion of natural gas service for future customers and/or about requiring customers in different areas of the state to pay for upgrades to serve the Rochester area.[620] One individual stated that she is on a limited income and cannot afford to pay more for her gas service.[621] Another individual expressed similar concerns.[622] The same individual voiced her concern that not enough members of the public understand the impact of this proceeding, which she believes is "a big deal."[623] One individual asked questions about MERC's renewable energy commitment.[624] Another individual requested that no frack or tar sands oil be used on the system.[625]

[612] *Id.* at 22-27.
[613] *Id.* at 27-28.
[614] Sign In Sheet Rochester 1:00 p.m. Public Hearing (July 12, 2016); Sign In Sheet Rochester 6:00 p.m. Public Hearing (July 12, 2016).
[615] Rochester 1:00 p.m. Tr. at 32-36 (July 12, 2016) (Carey).
[616] *Id.* at 44-56 (Borrud).
[617] *Id.* at 72-75 (Hendrickson).
[618] *Id.* at 37-38 (Hardin).
[619] *Id.* at 30-31 (Carey).
[620] *Id.* at 56-58, 61-66, 77 (Borrud, Hardin, Carey).
[621] *Id.* at 43 (Hardin).
[622] *Id.* at 66-71 (Eckert).
[623] *Id.* at 82 (Eckert).
[624] *Id.* at 33 (Carey).
[625] *Id.* at 63-66 (Eckert).

B. Albert Lea Public Hearing

9. A public hearing was held on July 13, 2016, at City Hall, 221 East Clark Street, in Albert Lea. The public hearing commenced at 6:00 p.m.

10. Rory Lenton, External Affairs Leader, attended the Albert Lea public hearing on behalf of MERC. Julie Urban, Utilities Economist, attended the Albert Lea public hearing on behalf of the OAG. Adam Heinen, Rates Analyst, attended the Albert Lea public hearing on behalf of the Department. Kevin George, Public Advisor, and Clark Kaml, Rates Analyst, of the Commission staff also attended the public hearing.

11. Several presentations were made at the outset of the Albert Lea public hearing. Rory Lenton presented information on MERC and the Project.[626] Adam Heinen provided information on the Department's involvement in the process.[627] Julie Urban provided information on the OAG's position on the Project.[628]

12. Nine members of the public attended the public hearing in Albert Lea.[629]

13. All members of the public were afforded a full opportunity to make a statement on the record and/or to ask questions.

14. Six members of the public made comments on the record. All of the speakers questioned the fairness and reasonableness of having to pay for a Project expanding natural gas service to the Rochester area only. Chad Adams, the City Manager for Albert Lea, and Randy Kehr, the Executive Director of the Freeborn County Chamber of Commerce, do not believe the City of Albert Lea or Freeborn County will receive direct benefits from the expansion Project in the near future.[630] Mr. Adams noted that the planned route for the Project will follow the perimeter of Rochester.[631]

15. Several individuals opined that if Rochester needs added capacity, then Rochester customers should pay for all or most of the costs of the added capacity.[632] One individual pointed out that Olmsted County, where Rochester is located, ranks sixth in personal income in Minnesota, whereas Freeborn County, where Albert Lea is located, ranks 56th.[633]

16. Ryan Nolander, the Executive Director of the Albert Lea Economic Development Agency, stated that rate increases make his job of attracting businesses

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[626] Albert Lea Public Hearing Transcript (Albert Lea Tr.) at 11-20 (July 13, 2016).
[627] Albert Lea Tr. at 20-22 (July 13, 2016).
[628] *Id.* at 23-26.
[629] Sign In Sheet Albert Lea Public Hearing (July 13, 2016).
[630] Albert Lea Tr. at 28-29, 32-33 (July 13, 2016) (Adams, Kehr).
[631] *Id.* at 28 (Adams).
[632] *Id.* at 29-31, 34, 38 (Adams, Axsmith, Nolander, Eckart, Baker).
[633] *Id.* at 30 (Axsmith).

and industry to the area harder.[634] He believes that if the benefits of the Project are going to be received by Rochester, then Rochester customers should pay for it.[635]

17. One individual talked about the struggle of being a retiree living on Social Security and trying to cover rate increases for energy.[636]

C. Rosemount Public Hearing

18. A public hearing was held on July 14, 2016, at Steeple Center Assembly Hall, 14375 South Robert Trail in Rosemount. The public hearing commenced at 1:00 p.m.

19. Jeff Larson, External Affairs Manager, and David Kult, General Manager of Operations and Engineering, attended the Rosemount public hearing on behalf of MERC. Julie Urban, Utilities Economist, attended the Rosemount public hearing on behalf of the OAG. Adam Heinen, Rates Analyst, attended the Rosemount public hearing on behalf of the Department. Bob Brill, Financial Analyst, attended the Rosemount public hearing on behalf of the Commission.

20. Two members of the public attended the public hearing in Rosemount.[637]

21. Both members of the public were afforded a full opportunity to make a statement and/or to ask questions. No person opted to make any comments or ask any questions.[638]

D. Cloquet Public Hearing

22. A public hearing was held on July 15, 2016, at City Hall, 1307 Cloquet Avenue, in Cloquet. The public hearing commenced at 1:00 p.m.

23. David Kult, General Manager of Operations and Engineering, attended the Cloquet public hearing on behalf of MERC. Joseph Dammel, Assistant Attorney General, attended the Cloquet public hearing on behalf of the OAG. Michael Ryan, Rates Analyst, attended the Cloquet public hearing on behalf of the Department.

24. Several presentations were made at the outset of the Cloquet public hearing. First, David Kult presented information on MERC and the Project.[639] Second, Joseph Dammel provided information on the OAG's position on the Project.[640] Last, Michael Ryan explained the Department's involvement in the process.[641]

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[634] *Id.* at 31 (Nolander).
[635] *Id.* at 31 (Nolander).
[636] *Id.* at 34 (Eckart).
[637] Sign In Sheet Rosemount Public Hearing (July 14, 2016).
[638] Rosemount Public Hearing Transcript (Rosemount Tr.) at 3 (July 14, 2016).
[639] Cloquet Public Hearing Transcript (Cloquet Tr.) at 9-16 (July 15, 2016).
[640] *Id.* at 16-19.
[641] *Id.* at 19-21.

25. One member of the public attended the public hearing in Cloquet.[642] The individual stated his belief that all MERC customers in the state should contribute to the Project costs because payment by all customers will lower the amount of the bill increase that any individual customer will experience.[643] The individual also recommended that future projects in other areas be treated in the same manner.[644]

Written Public Comments

A. SpeakUp Comments

26. Seventeen members of the public submitted comments using the SpeakUp platform on the Commission's website.

27. A majority of the individual commenters agreed that the costs of the expansion Project in Rochester should be paid for by the people who will directly benefit from it, not by customers across the state.[645] Many compared it to an assessment, meaning those who use it must pay for most of the costs of the Project.

28. Several commenters believe MERC is not being fiscally responsible with its approach to paying for the expansion Project.[646] One commenter questioned whether MERC has determined if funding might be available from other areas of its budget,[647] and several other commenters believe the profits made from the expansion should be used to fund the Project.[648] Another commenter stated that any increase to MERC's rates would harm business customers.[649]

B. Other Written Comments

29. Twenty-eight members of the public filed written comments with the Commission by U.S. Mail.

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[642] Sign In Sheet Cloquet Public Hearing (July 15, 2016).
[643] Cloquet Tr. at 22-23 (July 15, 2016) (Unulock).
[644] *Id.*
[645] *See, e.g.,* Comment by Larry Pahl (July 2, 2016) (SpeakUp) (eDocket No. 20167-123732-01); Comment by Randy and Colleen Tscheu (June 25, 2016) (SpeakUp) (eDocket No. 20167-123732-01); Comment by Dave Stevens (June 25, 2016) (SpeakUp) (eDocket No. 20167-123732-01); Comment by Paul Deeming (July 8, 2016) (SpeakUp) (eDocket No. 20167-123732-01); Comment by Denise Zeitz (June 30, 2016) (SpeakUp) (eDocket No. 20167-123732-01); Comment by James Borgschatz (June 29, 2016) (SpeakUp) (eDocket No. 20167-123732-01).
[646] Comment by Gilbert Peters (July 1, 2016) (SpeakUp) (eDocket No. 20167-123732-01); Comment by Tina Brady (June 27, 2016) (SpeakUp) (eDocket No. 20167-123732-01); Comment by Mary Kay Riendeau (June 28, 2016) (SpeakUp) (eDocket No. 20167-123732-01); Comment by James Nelson (July 12, 2016) (SpeakUp) (eDocket No. 20167-123732-01).
[647] Comment by Gilbert Peters (July 1, 2016) (SpeakUp) (eDocket No. 20167-123732-01).
[648] Comment by Tina Brady (June 27, 2016) (SpeakUp) (eDocket No. 20167-123732-01); Comment by Mary Kay Riendeau (June 28, 2016) (SpeakUp) (eDocket No. 20167-123732-01); Comment by James Nelson (July 12, 2016) (SpeakUp) (eDocket No. 20167-123732-01).
[649] Comment by Judy Sundby (June 30, 2016) (eDocket No. 20167-123732-01).

1) Comments by Individuals

30. A majority of the individuals who filed comments believe the costs of the expansion Project should be paid for by the people who will directly benefit from it, not by customers across the state.[650]

31. Several individuals commented on the hardship of dealing with rising energy costs and bills when living on a fixed income.[651]

32. One individual, a retired engineer, highlighted that insufficient natural gas service in Minnesota means people might "freeze to death given the harsh climate" in the state, and therefore increasing the dependability of natural gas service is important.[652]

2) Comments by Government and Businesses Interests

33. The Chair of the Rochester Public School Board, Gary Smith, submitted a letter of support for the Project, stating that "[w]e cannot continue to build upon our success as an institution of education without [increased natural gas in our community]."[653]

34. Jim Bier, an Olmsted County Commissioner, submitted a letter of support stating that "new natural gas infrastructure is the only practical option to adapt to Rochester's growth of residents and businesses."[654] The City of Rochester also submitted a letter of support stating that "additional natural gas resources are and will be needed to serve this area of southeastern Minnesota and the City of Rochester."[655]

35. A group of Minnesota legislators serving Olmsted and Dodge Counties filed a letter of support urging that the expansion Project and associated cost recovery "is essential to ensure continued adequate and reliable natural gas service for customers in and around Rochester now and in the future."[656] The group believes that "[w]ithout this capacity expansion and system upgrade current customers will experience greater risk of interruption and new customers may be denied natural gas service."[657]

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[650] Comment by Ben Cuba (July 28, 2016) (eDocket No. 20167-123755-01); Comment by Helen Murphy (July 21 & 22, 2016) (eDocket No. 20167-123755-01); Comment by Gregory Hudak (June 30, 2016) (eDocket No. 20167-123755-01); Comment by Lance Egley (July 4, 2016) (eDocket No. 20167-123755-01); Comment by Howard Healt (July 11, 2016) (eDocket No. 20167-123755-01); Comment by Duane Bond (July 28, 2016) (eDocket 20167-123755-01).
[651] Comment by Howard Healt (July 11, 2016) (eDocket No. 20167-123755-01); Comment by Christine Tetzlaff (July 6, 2016) (eDocket No. 20167-123755-01); Comment by Clifford Evjen (June 30, 2016) (eDocket No. 20167-123755-01); Comment by Judith Luchsinger (July 6, 2016) (eDocket No. 20167-123755-01).
[652] Comment by Thomas DeBoer (July 23, 2016) (eDocket No. 20168-124373-01).
[653] Comment by Gary Smith, Rochester Public Schools (July 17, 2016) (eDocket No. 20168-124373-01).
[654] Comment by Jim Bier, Olmsted County Commissioner (July 28, 2016) (eDocket No. 20168-124373-01).
[655] Comment by Ardell Brede, City of Rochester (July 26, 2015) (eDocket No. 20168-124373-01).
[656] Comment by Sen. Dave Senjem, Sen. Carla Nelson, Rep. Duane Quam, Rep. Kim Norton, and Rep. Nels Pierson (July 28, 2016) (eDocket No. 20168-124373-01).
[657] *Id.*

36. Two businesses based in Rochester, Seneca Foods and Textile Care Services, submitted letters of support urging approval of the expansion Project and recovery costs to meet the growing natural gas service needs of local commercial and industrial customers.[658]

37. Mayo Clinic and the Destination Medical Center Economic Development Agency (DMCEDA) submitted letters of support, claiming that natural gas service reliability is operationally critical.[659] DMCEDA planning estimates that up to 35,000 new jobs may be created in Rochester by 2040.[660] According to the DMCEDA, sufficient natural gas resources will be required to serve new homes and businesses.[661]

38. Walter Schlink, the Chief Energy Supply Officer for Rochester Public Utilities, filed a letter of support stating that the expansion Project will "ensure continued adequate and reliable natural gas service for customers in and around Rochester now and in the future."[662] According to the letter, "natural gas provides a reliable and relatively clean (compared to alternatives) source of electricity and heat" for a community facing "robust growth" in both the residential and commercial sectors.[663] Rochester is committed to emphasizing renewable energy sources as part of a long-term strategy to phase out fossil fuels and the City is committed to the increased presence of renewable energy sources.[664] Nevertheless, Mr. Schlink stated that the use of natural gas for electric generation and production of steam remains an important part of Rochester Public Utilities' portfolio and will remain so for the foreseeable future.[665] Mr. Schlink also stated that its interruptible transportation service from MERC is likely to increase dramatically in the coming years.[666]

39. The Rochester Area Chamber of Commerce and Rochester Area Economic Development, Inc. submitted letters of support urging approval of the expansion project and recovery.[667]

40. Letters of support were also filed by the Southeast Minnesota Association of Realtors, the Rochester Area Builders Association, and the Laborers District Council

[658] Comment by Paul Jewson, Textile Care Services (May 5, 2016) (eDocket No. 20168-124373-01); Comment by Dave Elfstrand, Seneca Foods Corporation (July 27, 2016) (eDocket No. 20168-124373-01).
[659] Comment by Brett Gorden, Mayo Clinic (July 28, 2016) (eDocket No. 20168-124373-01); Comment by Lisa Clarke, Destination Medical Center (July 28, 2016) (eDocket No. 20168-124373-01).
[660] Comment by Lisa Clarke, Destination Medical Center (July 28, 2016) (eDocket No. 20168-124373-01).
[661] *Id.*
[662] Comment by Walter Schlink, Rochester Public Utilities (July 27, 2016) (eDocket No. 20168-124373-01).
[663] *Id.*
[664] *Id.*
[665] *Id.*
[666] *Id.*
[667] Comment by Julie Fiesel, Rochester Area Chamber of Commerce (July 27, 2016) (eDocket No. 20168-124373-01); Comment by Gary Smith, Rochester Area Economic Development, Inc. (June 23, 2016) (eDocket No. 20168-124373-01).

of Minnesota and North Dakota.[668] All three organizations believe the expansion Project and cost recovery are essential to accommodate growth in the Rochester area.[669]

[668] Comment by Patrick Sexton, SouthEast Minnesota Association of Realtors (July 22, 2016) (eDocket No. 20168-124373-01); Comment by John Eischen, Rochester Area Builders Association (July 27, 2016) (eDocket No. 20168-124373-01); Comment by Todd Pufahl, Laborers District Council of Minnesota and North Dakota (May 20, 2016) (eDocket No. 20168-124373-01).

[669] Comment by Patrick Sexton, SouthEast Minnesota Association of Realtors (July 22, 2016) (eDocket No. 20168-124373-01); Comment by John Eischen, Rochester Area Builders Association (July 27, 2016) (eDocket No. 20168-124373-01); Comment by Todd Pufahl, Laborers District Council of Minnesota and North Dakota (May 20, 2016) (eDocket No. 20168-124373-01).

MINNESOTA
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November 30, 2016

See Attached Service List

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

OAH 68-2500-33191
MPUC G-011/M-15-895

To All Persons on the Attached Service List:

Enclosed and served upon you is the Administrative Law Judge's **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** in the above-entitled matter.

If you have any questions, please contact my legal assistant Denyse Johnson at (651) 361-7888 or denyse.johnson@state.mn.us, or facsimile at (651) 539-0310.

Sincerely,

Jeanne Cochran

JEANNE M. COCHRAN
Administrative Law Judge

JMC:dj
Enclosure
cc: Docket Coordinator

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
PO BOX 64620
600 NORTH ROBERT STREET
ST. PAUL, MINNESOTA 55164

CERTIFICATE OF SERVICE

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

Denyse Johnson, certifies that on November 30, 2016 she served the true and correct **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** by eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
Mitchell	Abeln	mitchellabeln@dmceda.org	Destination Medical Center - Economic Development Agency	195 W Broadway Rochester, MN 55902	Electronic Service	No
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Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes
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First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret
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