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June 24, 2014

<u>VIA ELECTRONIC FILING</u>

The Honorable Eric L. Lipman
Administrative Law Judge
Office of Administrative Hearings
P.O. Box 64620
St. Paul, MN 55101

Re: In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota
MPUC Docket No. G-011/GR-13-617
OAH Docket No. 8-2500-31126

Dear Judge Lipman:

On behalf of Minnesota Energy Resources Corporation (MERC), enclosed for filing in the above matter, please find MERC's Initial Post-Hearing Brief and Proposed Findings of Fact, Conclusions of Law, and Recommendation.

Thank you for your attention to this matter. Please feel free to contact me at (612) 340-2881 if you have any questions.

Sincerely yours,

/s/ Michael J. Ahern

Michael J. Ahern

Enclosure

cc: Service List

STATE OF MINNESOTA

BEFORE THE OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota	MPUC DOCKET No. G-011/GR-13-617 OAH Docket No. 16-2500-21807-2

MINNESOTA ENERGY RESOURCES CORPORATION'S PROPOSED FINDINGS OF FACT, CONCLUSIONS, AND RECOMMENDED ORDER

June 24, 2014

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This matter came for evidentiary hearing before Administrative Law Judge ("ALJ") Eric L. Lipman on May 13, 2014, at the offices of the Minnesota Public Utilities Commission in St. Paul, Minnesota. Public hearings were held on March 12, 2014, in Rochester and Rosemount, and on March 13, 2014 in Cloquet. Public comments were received until March 19, 2014.

Michael J. Ahern, Kristin M. Stastny, and Kristin K. Berkland, Attorneys at Law, Dorsey & Whitney LLP, 50 South Sixth Street, Suite 1500, Minneapolis, Minnesota 55402, appeared on behalf of Minnesota Energy Resources Corporation ("MERC" or the "Company").

Chad T. Marriott, Attorney at Law, Stoel Rivers, LLP, 900 SW Fifth Avenue, Suite 2600, Portland, Oregon 97204, appeared for and on behalf of the Super Large Gas Intervenors.

Richard J. Savelkoul, Attorney at Law, Martin & Squires, P.A., 332 Minnesota Street, Suite W2750, St. Paul, Minnesota 55101, appeared for and on behalf of Constellation New Energy – Gas Division, LLC ("Constellation").

Julia E. Anderson, Linda S. Jensen, and Peter Madsen, Assistant Attorneys General, 445 Minnesota Street, Suite 1800, St. Paul, Minnesota 55101, appeared for and on behalf of the Department of Commerce, Division of Energy Resources, Energy Regulation and Planning ("Department").

Ian M. Dobson and Ryan P. Barlow, Assistant Attorneys General, 445 Minnesota Street, Suite 1400, St. Paul, Minnesota 55101, appeared for and on behalf of the Office of the Attorney General, Antitrust and Utilities Division ("OAG-AUD").

Robert Harding, Clark Kaml, Robert Brill, Ann Schwieger and Andrew Bahn, 121 Seventh Place East, Suite 350, St. Paul, Minnesota 55101, attended the hearings on behalf of the Staff of the Public Utilities Commission ("Commission").

STATEMENT OF ISSUES

On September 30, 2013, MERC filed a general rate case seeking an annual increase in its natural gas rates of $14,187,597, or 5.52 percent.[1] On November 27, 2013, the Commission issued a Notice and Order for Hearing referring the matter to the Office of Administrative Hearings for contested case proceedings.[2] The Commission's November 27, 2013 Order directed the parties to specifically and thoroughly address the following issues in the course of the contested case proceedings:

1) Is the test revenue increase sought by the Company reasonable or will it result in unreasonable and excessive earnings?

2) Is the rate design proposed by the Company reasonable?

3) Are the Company's proposed capital structure, cost of capital, and return on equity reasonable?

The Commission further requested that the parties address MERC's test year forecast for late payment and other revenues in their prefiled direct testimony and address and fully develop the record on MERC's proposed test-year regulatory assets and liabilities. The Commission also asked that the parties address the reasonableness of MERC's joint rate service with respect to both gas and non-gas costs and rates, and whether MERC's joint rate tariff language needs to be clarified to better explain how MERC administers this service.[3]

FINDINGS OF FACT

I. INTRODUCTION

A. Description of the Company

1. MERC is a corporation organized under the laws of the state of Delaware, authorized to do business in Minnesota, with its principal office located in Rosemount, Minnesota. MERC is a subsidiary of Integrys and is one of six subsidiaries of Integrys Energy Group, which also owns Wisconsin Public Service Corporation, Upper Peninsula Power Company, Michigan Gas Utilities Corporation, The Peoples Gas Light and Coke Company, and North Shore Gas Company, which provide natural gas and electric service in the states of Wisconsin, Illinois and Michigan.[4]

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1 Ex. 16 at 5 (B. Nick Direct); Ex. 2 Initial Filing Volume 1: Summary of Filing.

2 NOTICE AND ORDER FOR HEARING (Nov. 27, 2013) (Docket No. G-011/GR-13-617) (Doc. ID No. 201311-94140-01).

3 NOTICE AND ORDER FOR HEARING (Nov. 27, 2013) (Docket No. G-011/GR-13-617) (Doc. ID No. 201311-94140-01).

4 Ex. 16 at 3 (B. Nick Direct).

2. MERC serves gas to approximately 213,000 customers in 51 counties and 165 communities throughout Minnesota. MERC's gas service territories include customers in the southern, east central and northern portions of the state.[5]

3. MERC's last rate case was Docket No. G-007,011/GR-10-977. The Commission issued its Findings of Fact, Conclusions, and Order approving final rates in that proceeding on July 13, 2012. The Commission authorized rate relief based on a 9.70 percent return on common equity.[6]

B. Jurisdiction

4. The Commission has general jurisdiction over MERC under Minn. Stat. §§ 216B.01 and 216B.02. The Commission has specific jurisdiction over the rate changes requested by the Company under Minn. Stat. § 216B.16.

5. The case was properly referred to the Office of Administrative Hearings under Minn. Stat. §§ 14.48-14.62 and Minn. Rules 1400.0200, et seq.

C. Overview and Procedural Background

6. On September 30, 2013, MERC filed an application for authority to increase natural gas rates in Minnesota, seeking an annual increase of $14,187,597, or approximately 5.52 percent over current rates.[7] MERC's application included proposed interim and final rate schedules, and was based on a 2014 test year.[8] The Company's proposed interim rate schedules identified an interim revenue deficiency of $12,401,502, or 4.82 percent, and requested an interim rate increase of $12,095,382, or 4.70 percent, beginning January 1, 2014.[9]

7. On November 27, 2013, the Commission accepted MERC's filing as substantially complete as of September 30, 2013, and suspended the operation of the proposed rate schedule

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5 Ex. 16 at 3 and Schedule (BAN-1) (B. Nick Direct).

6 *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G-007,011/GR-10-977, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 20 (July 13, 2012) (Doc. ID No. 20127-76778-01).

7 Ex. 2 Initial Filing Volume 1: Notice of Change in Rates, Interim Rate Petition, Summary of Filing (Sept. 30, 2013).

8 Ex. 2 Initial Filing Volume 1: Notice of Change in Rates, Interim Rate Petition, Summary of Filing (Sept. 30, 2013).

9 ORDER SETTING INTERIM RATES (Nov. 27, 2013) (Docket No. G-011/GR-13-617) (Doc. ID No. 201311-94139-01).

under Minn. Stat. § 216B.16, subd. 2, until a final determination in this case.[10] The Commission also referred the case to the Office of Administrative Hearings for contested case proceedings.[11]

8. Minnesota Statutes section 216B.16, subd. 2(e) provides MERC with the statutory right to a final determination by the Commission within 10 months of the initial filing date. If the Commission finds that is insufficient time due to the need to make a final determination in any other pending rate case, the statute authorizes the Commission to extend the suspension period up to 90 additional calendar days. In its Order Accepting MERC's Filing, the Commission determined to extend the suspension period until October 28, 2014, to ensure adequate evidentiary development and informed decision-making.[12]

9. The Commission granted MERC's request for an interim rate increase, authorizing an interim rate increase of $10,755,973 and authorized MERC to put the interim rates into effect on November 29, 2013. The Commission acknowledged MERC's request to not begin charging the authorized interim rates until January 1, 2014 and MERC's right to waive its right to charge interim rates for that period.[13]

10. The Commission also approved MERC's request to withhold collection of the full amount of the interim rate increase from its Super Large Volume ("SLV") customer class. The Commission found that MERC presented "exigent circumstances" under Minn. Stat. § 216B.16, subd. 3, because its SLV customers are sensitive to rate increases, and have the ability to bypass MERC's system, which would potentially result in increased rates for MERC's remaining customers.[14]

11. As part of the interim rate order, the Commission also authorized an incorporation of a new base cost of gas set in conjunction with the base cost of gas proceeding in Docket No. Docket No. G011/M-13-732.[15] The Commission required that MERC update the base cost

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[10] *See* ORDER ACCEPTING FILING, SUSPENDING RATES, AND EXTENDING TIME FOR FINAL DETERMINATION (Nov. 27, 2013) (Docket No. G-011/GR-13-617) (Doc. ID No. 201311-94138-01); NOTICE AND ORDER FOR HEARING (Nov. 27, 2013) (Docket No. G-011/GR-13-617) (Doc. ID No. 201311-94140-01).

[11] NOTICE AND ORDER FOR HEARING (Nov. 27, 2013) (Docket No. G-011/GR-13-617) (Doc. ID No. 201311-94140-01).

[12] *See* Order ACCEPTING FILING, SUSPENDING RATES, AND EXTENDING TIME FOR FINAL DETERMINATION (Nov. 27, 2013) (Docket No. G-011/GR-13-617) (Doc. ID No. 201311-94138-01).

[13] ORDER SETTING INTERIM RATES at 2, 5 (Nov. 27, 2013) (Docket No. G-011/GR-13-617) (Doc. ID No. 201311-94139-01).

[14] ORDER SETTING INTERIM RATES at 3-4 (Nov. 27, 2013) (Docket No. G-011/GR-13-617) (Doc. ID No 201311-94139-01).

[15] *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a New Base Cost of Gas for Interim Rates in Docket No. G011/M-13-732*, ORDER SETTING NEW BASE COST OF GAS, Docket No. G011/M-13-732 (Nov. 27, 2013) (Doc. ID No. 201311-94132-01).

of gas at least once during the contested case proceeding and file such update in both the base cost of gas docket, Docket No. G011/M-13-732, and this docket.[16]

12. In accordance with the Commission's order, MERC is collecting interim rates subject to refund if the rates exceed the final rates determined by the Commission.[17]

13. On December 10, 2013, ALJ Eric L. Lipman conducted a prehearing conference at the Public Utilities Commission, 350 Metro Square Building, 121 Seventh Place East, St. Paul, Minnesota.[18]

14. ALJ Lipman issued the first prehearing order on December 12, 2013 and protective order on December 23, 2013.[19] In the first pre-hearing order, ALJ Lipman ordered that petitions for intervention be filed by February 14, 2014; that direct testimony of intervenors be filed by March 4, 2014; that rebuttal testimony of all parties be filed by April 15, 2014; and that the evidentiary hearing take place on May 13-16, 2014.[20]

15. The initial parties to the proceeding were MERC, the Department, and the OAG-AUD.[21]

16. On February 14, 2014, Constellation filed a Petition to Intervene.[22]

17. On February 14, 2014, the Hibbing Taconite Company, ArcelorMittal USA's Minorca Mine, Northshore Mining Company, United Taconite, LLC, the Minntac and Keewatin Mines of United States Steel Corporation, and USG Interiors, Inc., (collectively appearing as the "Super Large Gas Intervenors") filed a Petition to Intervene.[23]

18. MERC did not object to the intervention of the Super Large Gas Intervenors or Constellation as parties to this matter.

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[16] *In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a New Base Gas Cost for Interim Rates*, Docket No. G-011/M-13-732 , ORDER SETTING NEW BASE COST OF GAS (Nov. 27, 2013) (Doc. ID No. 201311-94132-01); *see* Ex. 9 (Compliance Filing – Update to Commodity Cost of Gas).

[17] ORDER SETTING INTERIM RATES at 2 (Nov. 27, 2013) (Docket No. G-011/GR-13-617) (Doc. ID No. 201311-94139-01).

[18] *See* First Prehearing Order (Dec 12, 2013) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 201312-94534-01).

[19] *See* First Prehearing Order (Dec. 12, 2013) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 201312-94534-01); Second Prehearing Order (Protective Order) (Dec. 23, 2013) (Doc. ID No. 201312-94841-01).

[20] *See* First Prehearing Order (Dec. 12, 2013) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 201312-94534-01).

[21] *See* First Prehearing Order (Dec. 12, 2013) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 201312-94534-01).

[22] *See* Petition to Intervene filed by Constellation New Energy – Gas Division, LLC (Feb. 14, 2014) (Doc. ID No. 20142-96453-03).

[23] *See* Petition to Intervene filed by Super Large Gas Intervenors (Feb. 14, 2014) (Doc. ID No. 20142-96453-03).

19. On February 24, 2014, U.S. Energy Services, Inc. on behalf of itself and a group of industrial, commercial, and institutional customers (collectively the "ICI Group") filed a Petition to Intervene.[24]

20. On February 26, 2014, ALJ Lipman issued a Third Prehearing Order, granting the intervention of Constellation and the Super Large Gas Intervenors and requesting additional information from the ICI Group as to which interruptible transport service customers it sought to represent.[25]

21. The ICI Group filed a supplement to its Petition to Intervene on February 27, 2014.[26]

22. MERC filed an objection to the ICI Group's untimely petition to intervene on March 3, 2014.[27]

23. Oral arguments on the ICI Group's Petition to Intervene were held on March 14, 2014.[28]

24. An Order denying the intervention of the ICI Group was issued on March 24, 2014.[29]

25. The Super Large Gas Intervenors, though a party to the proceeding, did not submit testimony or actively participate in this proceeding.

26. MERC filed direct testimony on September 30, 2013.[30]

27. MERC filed supplemental direct testimony on December 26, 2013.[31]

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[24] *See* Petition to Intervene filed by U.S. Energy Services, Inc. (Feb. 24, 2014) (Doc. ID No. 20142-96752-01).

[25] *See* Third Prehearing Order (Feb. 26, 2014) (Docket OAH 8-2500-31126; MPUC G-011/GR-13-617) (Doc. ID No. 20142-96812-01).

[26] Supplement to Petition to Intervene (Feb. 27, 2014) (OAH Docket No. 8-2500-31126; MPUC Docket G-011/GR-13-617) (Doc. ID No. 20142-96880-01).

[27] *See* Objection to Petition to Intervene of U.S. Energy Services, Inc. and Affidavit in Support (Mar. 3, 2014) (OAH Docket No. 8-2500-31126; MPUC Docket G-011/GR-13-617) (Doc. ID Nos. 20143-96996-01 and 20143-96996-02).

[28] Fourth Prehearing Order (Mar. 11, 2014) (OAH Docket No. 8-2500-31126; MPUC Docket G-011/GR-13-617) (Doc. ID No. 20143-97235-01).

[29] *See* Fifth Prehearing Order (Mar. 24, 2014) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 20143-97542-01).

[30] *See* Ex. 16 (B. Nick Direct); Ex. 19 (S. DeMerritt Direct); Ex. 38 (H. John Direct); Ex. 26 (C. Hans Direct); Ex. 14 (D. Kult Direct); Ex. 12 (T. Kupsh Direct); Ex. 13 (N. Cleary Direct); Ex. 10 (B. Kage Direct); Ex. 11 (M. Gerth Direct); Ex. 36 (J. Wilde Direct); Ex. 28 (L. Gast Direct); Ex. 17 (P. Moul Direct); Ex. 29 (J. Hoffman-Malueg Direct); Ex. 40 (G. Walters Direct).

[31] *See* Exs. 21-23 (S. DeMerritt Supplemental Direct and Exhibits to S. DeMerritt Supplemental Direct); Ex. 41 (G. Walters Supplemental Direct).

28. The Department, OAG-AUD, and Intervenor Constellation submitted direct testimony on March 4, 2014, March 20, 2014, April 21, 2014 and May 9, 2014.[32]

29. MERC, the Department, and the OAG-AUD filed rebuttal testimony on April 15, 2014 and April 21, 2014.[33]

30. Public hearings were held in Rochester and Rosemount on March 12, 2014.[34] Eight members of the public attended the meeting in Rochester and six spoke. One member of the public attended the meeting in Rosemount and spoke.[35]

31. An additional public hearing was held in Cloquet, Minnesota on March 13, 2014.[36] Three members of the public attended the hearing and all three spoke.[37]

32. MERC, the Department, and the OAG-AUD filed surrebuttal testimony on May 7, 2014 and May 9, 2014.[38]

33. The evidentiary hearing was held on May 13, 2014, at the Public Utilities Commission, Large Hearing Room, in St. Paul, Minnesota.

D. MERC's Requested Rate Increase

34. MERC requests an overall rate increase to earn a reasonable and fair rate of return, based on its 2014 test year. A number of key factors have caused the need for a rate increase. First, the 2012 historical year concluded with a $13,889,494 revenue deficiency for

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[32] *See* Ex. 125 (R. Haubensak Direct); Ex. 150 (Adopted Direct Testimony of V. Chavez by J. Lindell); Exs. 151-152 (J. Lindell Direct and Schedules); Exs. 155-157 (R. Nelson Direct, Errata and Schedules); Exs. 161-163 (P. Chattopadhyay Direct, Errata and Schedules); Ex. 200 (E. Amit Direct); Exs. 203-204 (S. Peirce Direct and Errata); Exs. 206-207 (S. Ouanes Direct and Attachments); Ex. 210 (M. Zajicek Direct); Exs. 212-13 (L. Otis Direct and Errata); Ex. 215 (L. La Plante Direct); Exs. 213, 217-218, 220 (M. St. Pierre Direct, Errata and Attachments).

[33] Ex. 15 (D. Kult Rebuttal); Ex. 18 (P. Moul Rebuttal); Ex. 24 (S. DeMerritt Rebuttal); Ex. 27 (C. Hans Rebuttal); Exs. 30-31 (J. Hoffman Malueg Rebuttal and Errata); Ex. 37 (J. Wilde Rebuttal); Ex. 39 (H. John Rebuttal); Ex. 42 (G. Walters Rebuttal); Ex. 153 (J. Lindell Rebuttal); Ex. 164 (P. Chattopadhyay Rebuttal); Ex. 201 (E. Amit Rebuttal); Ex. 208 (S. Ouanes Rebuttal).

[34] First Prehearing Order (Dec. 12, 2013) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 201312-94534-01).

[35] *See* Rochester Public Hearing Transcript (Mar. 12, 2014) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 20144-98117-01); Rosemount Public Hearing Transcript (Mar. 12, 2014) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 20144-98117-02).

[36] First Prehearing Order (Dec. 12, 2013) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 201312-94534-01).

[37] *See* Cloquet Public Hearing Transcript (Mar. 13, 2014) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 20144-98117-03).

[38] Ex. 25 (S. DeMerritt Surrebuttal); Ex. 154 (J. Lindell Surrebuttal); Ex. 158-60 (R. Nelson Surrebuttal and Schedules); Ex. 165-66 (P. Chattopadhyay Surrebuttal and Schedules); Ex. 202 (E. Amit Surrebuttal); Ex. 205 (S. Peirce Surrebuttal); Ex. 209 (S. Ouanes Surrebuttal); Ex. 211 (M. Zajicek Surrebuttal); Ex. 214 (L. Otis Surrebuttal); Ex. 216 (L. La Plante Surrebuttal); Ex. 219-20 (M. St. Pierre Surrebuttal and Errata).

MERC's operations, and the Company-projected 2014 test year indicated a revenue deficiency totaling $14,187,597.[39]

35. Second, general inflation, not including Known and Measurable ("K&M") items, has increased Operations and Maintenance ("O&M") expenses at a rate of 3.74 percent. Because of the decreased margin and increased expenses, MERC will not be afforded a reasonable opportunity to earn its rate of return or maintain the safe and reliable operation of its distribution system.[40]

36. Third, MERC has identified K&M changes from 2012 to 2014 that will impact MERC's 2014 costs of providing service. Overall, MERC's capital project expenditures have increased and it has filled vacant positions, which will result in additional compensation expenditures.[41]

37. Fourth, MERC has included in the test year its 2014 approved Conservation Improvement Plan ("CIP") expenses.[42]

38. Fifth, MERC has projected a continual increase in Property Tax Expense as discussed in MERC's last rate case, Docket No. G007, 011/GR-10-977.[43]

39. Sixth, MERC is requesting amortization of rate case expenses to occur over a two year period due to anticipated construction activity that may necessitate a 2015 rate case filing.[44]

40. Seventh, MERC has a right to a reasonable opportunity to earn its authorized Return on Equity ("ROE") for its operations. MERC's currently authorized rates will not provide sufficient revenue to allow MERC a reasonable opportunity to earn its authorized ROE. There are no significant cost cutting reductions that can be made without jeopardizing service quality, service reliability, and safety to the public or MERC's employees. MERC therefore believes it is necessary, just, and reasonable to request and obtain rate relief.[45]

41. MERC's initial filing indicated a need for an annual base rate increase of $14,187,597, or approximately 5.52 percent of total revenues.[46] Based on adjustments agreed to during this proceeding, MERC is requesting an annual base rate increase of $12,159,494, or approximately 4.1 percent.[47]

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39 Ex. 16 at 5 (B. Nick Direct); Ex. 19 at 3 (S. DeMerritt Direct).

40 Ex. 16 at 5 (B. Nick Direct); Ex. 19 at 3 and Schedule (SSD-18) (S. DeMerritt Direct).

41 Ex. 16 at 5-6 (B. Nick Direct); Ex. 19 at 14-15 (S. DeMerritt Direct).

42 Ex. 16 at 6 (B. Nick Direct); Ex. 24 at Schedule (SSD-1) (S. DeMerritt Rebuttal).

43 Ex. 16 at 6 (B. Nick Direct).

44 Ex. 16 at 6 (B. Nick Direct); Ex. 24 at 16-17 (S. DeMerritt Rebuttal).

45 Ex. 16 at 6-7 (B. Nick Direct); Ex. 17 at 1-2, 11 (P. Moul Direct).

46 Ex. 40 at Schedule 3 (GJW-1) (G. Walters Direct).

47 Ex. 42 at Schedule 3 (GJW-1) (G. Walters Rebuttal).

E. Summary of Public Comments

42. Public hearings on MERC's proposed rate increase were held on March 12, 2014, at Rochester, Minnesota (eight members of the public attended and six of the eight spoke); March 12, 2014, at Rosemount, Minnesota (one member of the public attended and spoke); and on March 13, 2014, at Cloquet, Minnesota (three members of the public attended and three spoke).[48]

43. At the public hearings individuals expressed concerns about fixed income hardship, transparency regarding rate changes, and the amount and frequency of rate increases. Other individuals raised questions regarding their customer bills and surcharges.[49]

44. Approximately six written comments from the public were also received.[50] A number of these recommended no rate increase, and at least one recommended a rate decrease.[51]

II. MERC'S REVENUE REQUIREMENT

45. The revenue requirements portion of a general rate case seeks to determine what additional revenue is required to meet the utility's required operating income, based on a "test year" of operations. The required operating income is derived from determining the amount of investments in rate base that have been made by a utility's shareholders, and multiplying the approved rate base times the rate of return that is determined to be appropriate for the company.[52]

46. After determining the required operating income, the company's test year expenses and revenues are evaluated to determine the current operating income for the test year (in this case 2014). The difference between the required operating income and the test year operating income is the income deficiency. The income deficiency is converted into a gross revenue deficiency amount.[53]

47. This section of the Proposed Findings pertains to the issues that were raised by the parties regarding MERC's rate base, test year expenses and revenues, and rate of return (computed from the approved capital structure, cost of debt, and authorized return on equity).

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[48] *See* Cloquet Public Hearing Transcript (Mar. 13, 2014) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 20144-98117-03).

[49] Rochester Public Hearing Transcript (Mar. 12, 2014) (OAH Docket No. 8-2500-31126; MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 20144-98117-01).

[50] *See, e.g.*, Public Comment, J. Eberhard (Doc. ID No. 20143-97433-01), Public Comment, PUC (Doc. ID No. 20143-97414-01), Public Comment, R. Bichel (Doc. ID No. 20143-97055-01), Public Comment, L. Rice (Doc. ID No. 20142-96533-01) and Public Comment, P. Pat (Doc. ID No. 20142-96117-01).

[51] *See, e.g.*, Public Comment, P. Pat (Doc. ID No. 20142-96117-01); Public Comment, L. Rice (Doc. ID No. 20142-96533-01); Public Comment, R. Bichel (Doc. ID No. 20143-97055-01); Public Comment, J. Eberhard (Doc. ID No. 20143-96533-01).

[52] Ex. 4 Initial Filing Volume 3: Informational Requirements, Document 1.

[53] Ex. 4 Initial Filing Volume 3: Informational Requirements, Document 1; Ex. 19 at Schedule (SSD-25) (S. DeMerritt Direct).

A. Rate of Return

48. Minn. Stat. § 216B.16, subd. 6, requires the Commission to give due consideration to the utility's need for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property, and an opportunity to earn a fair and reasonable return upon the investment in such property. The components of determining a fair and reasonable rate of return for MERC in this rate case include a determination of MERC's capital structure, MERC's cost of debt, and a reasonable return on common equity.

1. Capital Structure

49. To arrive at the cost of capital (overall rate of return), it is necessary to determine the amount of long-term debt, short-term debt, preferred stock, and common equity held by MERC. This represents MERC's capital structure. MERC proposed a projected capital structure consisting of 44.64 percent long-term debt, 5.06 percent short-term debt, and 50.31 percent common stock equity.[54]

50. The proposed capital structure reflected the Company's proposed 2014 average balances for long-term debt (13-month average), short-term debt (13-month average), and common equity (13-month average).[55]

51. The Department reviewed MERC's proposed capital structure and concluded that the proposed capital structure was reasonable.[56]

52. The ALJ finds that the capital structure proposed by MERC is reasonable and should be adopted in this case.

2. Cost of Debt

53. MERC proposed test-year cost of long-term debt of 5.5606 percent and short term cost of debt of 2.3487 percent, based on the 13-month average over the period December 1, 2013 through December 31, 2014.[57]

54. The Department reviewed MERC's proposed cost of long-term and short-term debt and concluded that it was reasonable.[58]

55. The ALJ finds that MERC's proposed cost of long-term and short-term debt is reasonable and should be approved.

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[54] Ex. 28 at 3-5 and Schedule (LJG-1) (L. Gast Direct).

[55] Ex. 28 at 3-5 (L. Gast Direct).

[56] Ex. 200 at 35-44 (E. Amit Direct); Ex. 202 at 12 (E. Amit Surrebuttal).

[57] Ex. 28 at 3-5 and Schedule (LJG-1) (L. Gast Direct).

[58] Ex. 200 at 35-44 (E. Amit Direct); Ex. 202 at 12 (E. Amit Surrebuttal).

3. Cost of Common Equity

56. The remaining variable in determining MERC's rate of return is to ascertain a reasonable rate of return on common equity, or ROE. Once determined, the resulting rate of return is applied to the authorized rate base of the company to determine MERC's required income.

57. Minn. Stat. § 216B.16, subd. 6, summarizes the factors that should be used to determine just and reasonable rates for a public utility, including the rate of return:

> The commission, in the exercise of its powers under this chapter to determine just and reasonable rates for public utilities, shall give due consideration to the public need for adequate, efficient, and reasonable service and to the need of the public utility for revenue sufficient to enable it to meet the cost of furnishing the service, including adequate provision for depreciation of its utility property used and useful in rendering service to the public, and to earn a fair and reasonable return upon the investment in such property.

58. These statutory requirements must be interpreted with regard to landmark United States Supreme Court decisions that set forth the constitutional tests used to determine the fairness or reasonableness of the rate of return. According to these cases:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties . . . The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[59]

59. The rate of return authorized for a public utility is directly related to the ability of the utility to meet its service responsibilities to its customers. A public utility is responsible for providing a particular type of service to its customers within a specific market area, and is not free to enter and exit competitive markets in accordance with available business opportunities. A regulated utility must compete for capital in the market, and the level of rates must carefully consider the public's interest in reasonably priced, as well as safe and reliable, service.[60]

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[59] Ex. 17, (P. Moul Direct), citing *Bluefield Water Works & Investment Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

[60] *See* Ex. 28 at 10 (L. Gast Direct); Ex. 200 at 2 (E. Amit Direct).

60. A fair rate of return is, by definition, the rate that will give the utility a reasonable return on its total investment.

61. Because MERC's stock is not traded in public markets, various financial models utilizing comparison groups must be used to estimate the reasonable return on common equity that should be authorized for MERC in this case.[61]

62. In its expert testimony, MERC presented a detailed analysis of the appropriate return on common equity, developed through the use of several accepted financial models, and updated this analysis in its rebuttal testimony.[62] MERC's analysis concluded that MERC's return on common equity should be set at 10.75 percent.[63] In Rebuttal Testimony, MERC stated that if the Commission does not agree with a 10.75 percent ROE for MERC, based on the increase in capital costs since MERC's last rate case, the equity return in this case should be at least 10.27 percent.[64]

63. The Department prepared an analysis of MERC's ROE in this case, and recommended that the Commission approve a ROE of 9.29 percent.[65]

64. The OAG-AUD prepared an analysis of MERC's ROE in this case, and recommended that the Commission approve a ROE of 8.62 percent.[66]

65. MERC determined its recommended ROE in this case by considering the results of three well-recognized measures of the cost of equity applied to market and financial data developed from a proxy group of nine natural gas companies from The Value Line Investment Survey and four combination gas and electric companies that are primarily delivery companies (i.e., they have no significant generation assets).[67] The three financial models that MERC used to develop its cost of equity are the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis and the Capital Asset Pricing Model ("CAPM"). MERC also considered as a check on the results of these models the Comparable Earnings ("CE") approach.[68] The ROE

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[61] Ex. 17 at 3-4 (P. Moul Direct).

[62] *See generally* Ex. 17 (P. Moul Direct) and Ex. 18 (P. Moul Rebuttal).

[63] This figure represents the results of Mr. Moul's updated analysis using data as of May 31, 2012. Ex. 18 at 3-5, 40 (P. Moul Rebuttal). Mr. Moul's original analysis was based on data as of May 31, 2012 and established a reasonable ROE of 10.75 percent. Ex. 17 at 1-2, 6, 46 and Schedule (PRM-1) (P. Moul Direct). *See also* Ex. 28 at 3, 10-11 (L. Gast Direct).

[64] Ex. 18 at 40 (P. Moul Rebuttal).

[65] This figure represents the results of Dr. Amit's updated analysis. Ex. 202 at 1-12 (D. Amit Surrebuttal). Dr. Amit's original analysis resulted in a recommended 9.40 percent ROE. Ex. 200 at 2, 27, 34 (E. Amit Direct); Ex. 201 at 27 (E. Amit Rebuttal).

[66] This figure represents the results of Dr. Chattopadhyay's updated analysis. Ex. 165 at 2 (P. Chattopadhyay Surrebuttal). Dr. Chattopadhyay's original analysis resulted in a recommended 8.90 percent ROE. Ex. 161 at 4, 57 (P. Chattopadhyay Direct).

[67] Ex. 17 at 4-5 (P. Moul Direct).

[68] Ex. 17 at 3-5 (P. Moul Direct); Ex. 18 at 3 (P. Moul Rebuttal).

must also reflect the risk factors that are unique to MERC for the ROE to be consistent with investor requirements.[69]

66. MERC updated the three models in Rebuttal Testimony and found that the updated cost of equity for the DCF model was 9.80 percent, the updated cost of equity for the RP model was 12.14 percent, and the updated cost of equity for the CAPM was 11.97 percent. The DCF results increased by .16 percent from MERC's Direct to Rebuttal Testimony. The RP results declined .25 percent from MERC's Direct to Rebuttal Testimony and the CAPM results increased by 1.08 percent from MERC's Direct to Rebuttal Testimony. With the results showing one increase, one decrease, and one result remaining mostly unchanged, MERC determined that the updated results continued to support the original 10.75 percent ROE recommendation.[70]

67. The DCF model attempts to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. The DCF return therefore consists of a current cash yield (the dividend yield) and future price appreciation (growth) of the investment.[71]

68. While widely used as an input to rate of return determinations in utility rate cases, the DCF model has limitations. The DCF analysis has a certain circularity when applied to the utility industry, because investors' expectations for the future depend on decisions of regulatory bodies. In turn, the regulatory bodies depend upon the DCF model to set the cost of equity, relying on investor expectations that include an assessment of how regulators will decide rate cases.[72]

69. Additionally, the DCF model has limitations that make it less useful in the rate setting process where the firm's market capitalization diverges significantly from the book value capitalization. Because this limitation leads to a mis-specified cost of equity when applied to a book value capital structure, an analysis needs to incorporate the required adjustment to correct this problem. MERC's updated DCF result was 9.80 percent.[73]

70. The Department also relied on the DCF method to determine an initial ROE for MERC of 9.40 percent and an updated ROE of 9.29 percent. In addition, the Department conducted two growth rate DCF analyses ("TGDCF"), using a comparison group of companies, to determine ROE. The Department used the CAPM model to support its DCF and TGDCF analyses.[74]

71. MERC determined that in light of the rates of return allowed by state utility commissions in 2013, the Department's recommended ROE was too low. Nationally there were

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[69] Ex. 17 at 8-11, 17 (P. Moul Direct); Ex. 18 at 4-5, 14-15 (P. Moul Rebuttal).

[70] Ex. 18 at 3-4 (P. Moul Rebuttal).

[71] Ex. 17 at 19-20 and Schedule (JPM-1) (P. Moul Direct).

[72] Ex. 17 at 19-20 (P. Moul Direct).

[73] Ex. 18 at 4 (P. Moul Rebuttal).

[74] Ex. 200 at 2-7, 24-26, 28-34 and Schedule (EA-12) (E. Amit Direct); Ex. 202 at 2 (E. Amit Surrebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 198-205 (E. Amit) (Doc. ID No. 20145-99937-01).

eleven (11) rate cases for natural gas utilities that were decided by state utility commissions in the fourth quarter of 2013. The measures of central tendency for these equity returns were 9.83 percent as the average, 9.84 percent as the median, and 9.67 percent as the midpoint (taken from a range of 9.08 percent to 10.25 percent). In contrast to measures of central tendency for the natural gas rate cases, there were nineteen (19) electric utility rate cases decided in the fourth quarter of 2013 with an average equity return of 9.89 percent, a median equity return of 10.00 percent, and a midpoint equity return of 10.06 percent (taken from a range of 8.72 percent to 11.40 percent).[75]

72. The Department responded that with respect to the 11 natural gas rate cases determined in the fourth quarter of 2013 with an allowed average rate of return of 9.83, the range of allowed ROEs was from a low of 9.08 percent to a high of 10.25 percent. Thus, some of the allowed ROEs were below the 9.40 percent ROE initially recommended by the Department. The Department concluded that based on the range of allowed ROEs, MERC's recommended ROE of 10.75 percent was unreasonably high. The Department also concluded that the Commission's decisions in the fourth quarter of 2013 were most likely based on data from 2012 and early 2013 and reflected dated economic and financial data that are not relevant to the current MERC rate case.[76]

73. MERC discounted the ROE from the Department's DCF analysis because Value Line projected an average rate of return of 11.49 percent for its natural gas utility companies over the 2017 through 2019 period. Based on this, and the fact that an update of the Commission's prior 9.70 percent approved equity return in MERC's last rate case, Docket No. G007,011/GA-10-977, results in a current return of 10.27 percent, MERC determined that the Department's recommended ROE was too low.[77]

74. To determine its proxy group, MERC began with the universe of gas utilities contained in the basic service of The Value Line Investment Survey, which consisted of eleven companies. MERC eliminated from the eleven NiSource, Inc., because of its natural gas pipeline and storage operations and UGI Corporation because of its highly diversified businesses. The remaining nine companies were included in MERC's proxy group. To this proxy group, MERC added four combination gas and electric utilities that are primarily delivery companies (i.e., they have no significant generation assets). The complete group, referred to as the "Delivery Group" is comprised of the following companies: AGL Resources, Inc. ("AGL"), Atmos Energy Corp. ("Atmos"), Consolidated Edison, Inc. ("Consolidated"), Laclede Group, Inc. ("Laclede"), New Jersey Resources Corp. ("NJR"), Northeast Utilities ("NU"), Northwest Natural Gas ("NWN"), PEPCO Holdings, Inc. "(PEPCO"), Piedmont Natural Gas Co. ("PNY"), South Jersey Industries, Inc. ("SJI"), Southwest Gas Corporation ("SWX"), UIL Holding Corporation ("UIL"), and WGL Holdings, Inc. ("WGL")[78]

75 Ex. 18 at 6 (P. Moul Rebuttal).

76 Ex. 202 at 18-19 (E. Amit Surrebuttal).

77 Ex. 18 at 8-9 (P. Moul Rebuttal).

78 Ex. 17 at 4-5 (P. Moul Direct).

75. The Department disagreed with MERC's Delivery Group because the group included four non-natural gas utility companies with higher risk profiles than the natural gas utilities selected by MERC. The Department argued that it is likely that investors base their valuation of such companies somewhat differently than their valuation of natural gas companies and recommended eliminating the four companies from MERC's Delivery Group. Because the Department felt that MERC did not provide any argument in its Rebuttal Testimony to justify the inclusion of the four non-natural gas utilities, the Department concluded that MERC's selection of the Delivery Group was inappropriate.[79]

76. The Department created its proxy group using a series of risk screens. The resulting group of eight companies was named the Natural Gas Comparison Group ("NGCG"). According to the Department, both MERC and the companies in the NGCG are mostly engaged in the distribution of natural gas and are similarly rate-of-return regulated by the states in which they operate. Therefore, the Department argued, business risks of the two groups are somewhat similar. Regarding specific risk measures, MERC is a subsidiary company and, therefore, does not have beta, Standard Deviation of Price Changes or a credit rating. Therefore, the Department feels that the only market-related quantitative risk measures available for comparison are the long-term debt ratios and the equity ratios.[80]

77. The Department's proxy group did not recognize observable risk factors in MERC's cost of equity. When risk differences can be identified between MERC and the proxy group, those differences must be addressed in the cost of equity analysis for MERC. It is particularly important not to focus just on the risk traits of the proxy group, such as their bond ratings, but to compare them to MERC, which has no bond rating. Absent a valid comparison between MERC and the proxy group, a "generically" derived cost of equity obtained from the proxy group has little bearing on the return requirements for MERC if the Company's risk is observably different. To ignore the factors that show higher risk for MERC, as compared with the Department's NGCG, will result in inadequate compensation for MERC's higher risk profile. In this case, the NGCG group assembled by the Department provides a portfolio of companies that reflects a composite risk that is less than MERC's risk, as evidenced by observable factors that distinguish the risk of MERC from the NGCG.[81]

78. The OAG-AUD created its proxy group using Value Line's universe of utilities that are categorized as gas utilities and gas and electric utilities. The OAG-AUD determined that in creating a proxy comparable to MERC, it is important that the companies in the proxy exhibit a fairly high percentage of regulated assets and have the majority of their revenue coming from gas utility operations. Also, as the OAG-AUD relied not only on earnings projections, but also on dividends and book value projections in its DCF analysis, the OAG-AUD only considered companies that are covered by Value Line Surveys because the OAG-AUD determined that dividends and book value projections are covered only by Value Line Survey.[82]

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79 Ex. 200 at 46-47 (E. Amit Direct); Ex. 202 at 13-14 (E. Amit Surrebuttal).

80 Ex. 200 at 7-13 and (EA-2) (E. Amit Direct).

81 Ex. 18 at 14-15 (P. Moul Rebuttal).

82 Ex. 161 at 25-27 (P. Chattopadhyay Direct).

79. MERC determined that the OAG-AUD utilized an inconsistent screening process in the selection of its proxy group and excluded four companies from the proxy group that made the group less relevant for purposes of this rate case proceeding. The OAG-AUD removed three natural gas companies and four combination delivery companies from its proxy group that were included in MERC's group. The exclusion of these companies was unnecessary. The OAG-AUD failed to show that the exclusion of these companies enhanced the risk profile of the companies that the OAG-AUD retained in its proxy group. The OAG-AUD also failed to consider four companies in its proxy group that MERC considered reasonable because all of the companies have natural gas distribution operations in addition to their electric delivery operations.[83]

80. The OAG-AUD discounted the Department's comparison group selection because the OAG-AUD disagreed with the Department's 60 percent regulated income screen, and beta and standard deviation screen. Specifically, the OAG-AUD argued that the percentage of regulatory income is highly influenced by the percentage of non-regulated income. Thus, the percentage of regulated income may not appropriately reflect the business profile of the company in question. In the alternative, the OAG-AUD proposed to use revenues and regulatory assets to screen companies for a comparison group.[84]

81. The Department concluded that the OAG-AUD failed to show that beta is an inappropriate measure of risk. With respect to the standard deviation screen, the Department determined that the standard deviation is a commonly used criterion to evaluate stock price volatility and investment risk. Whereas the Department's standard deviation of price changes is based on monthly price changes over a five-year period, the OAG-AUD used a 60-day period and did not provide data to support its calculations. The Department concluded that there was nothing in the OAG-AUD's Rebuttal Testimony that showed that using the standard deviation as a screening criterion is inappropriate.[85]

82. The OAG-AUD also relied on DCF methods to determine an initial ROE for MERC of 8.90 percent and an updated ROE of 8.62 percent. The OAG-AUD used the CAPM model to support its DCF analyses.[86] According to the OAG-AUD, the CAPM and RP methods predominantly use historical stock-price appreciation as the basis for measuring the expected return on common equity. According to the OAG-AUD, while this may provide insight into what returns investors expect based on past experience, it has limited value in assessing what returns are necessary to attract needed capital. In contrast, the DCF model is essentially forward looking. The OAG-AUD emphasized that it gave very little weight to the CAPM to arrive at the OAG-AUD's final ROE recommendations.[87]

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83 Ex. 18 at 25-26 (P. Moul Rebuttal).

84 Ex. 164 at 2-12 (P. Chattopadhyay Rebuttal); Ex. 202 at 22-23 (E. Amit Surrebuttal).

85 Ex. 202 at 25-29 (E. Amit Surrebuttal).

86 Ex. 161 at 4 (P. Chattopadhyay Direct); Ex. 165 at 2 (P. Chattopadhyay Surrebuttal).

87 Ex. 161 at 16, 22-23, 46 (P. Chattopadhyay Direct); Ex. 165 at 38 (P. Chattopadhyay Surrebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 179-186 (P. Chattopadhyay) (Doc. ID No. 20145-99937-01).

83. MERC argued that the OAG-AUD's initial recommended return on common equity of 8.90 percent was so low that it is inappropriate in this case. The 8.90 percent rate of return on common equity proposed by the OAG-AUD does not reflect a reasonable cost of equity in the current market environment. The OAG-AUD proposed to reduce the Company's return by -0.80 percent (8.90% - 9.70%) at a time when capital costs have increased since the Company's last rate case. In addition, the yield on Treasury bonds has increased by 1.07 percent (3.66% - 2.59%), which demonstrates that the OAG-AUD's proposal in this case will not result in a reasonable return.[88]

84. The OAG-AUD seems inclined toward a low return because the economy in Minnesota is performing well in comparison to other regions of the U.S. The OAG-AUD has not shown that MERC has benefitted from this phenomenon. It is undeniable that MERC has experienced historically high earnings variability and its operating ratio is well above average. These risk factors show that MERC requires an above average ROE to compensate for its above average risk.[89]

85. The OAG-AUD discounted MERC's DCF analysis because both the OAG-AUD's average market-to-book ratio and MERC's market-to-book ratio were over one. According to the OAG-AUD, a market-to-book ratio over one indicates that the true cost of equity is comfortably less than the ROE expected by investors in the gas industry. The OAG-AUD argued that in view of a market-to-book ratio over one, if the cost of equity is estimated based on expected return on common equity, the resulting return would unreasonably benefit shareholders at the expense of ratepayers.[90] The OAG-AUD concluded that when the market-to-book ratio is significantly greater than one, there exists an upward bias to the earnings growth rate.[91]

86. Both MERC and the Department disagreed with the OAG-AUD's conclusion that the DCF analysis results in an upwardly biased estimate of the cost of common equity when the market-to-book ratio is greater than one. Such a ratio is irrelevant for cost of equity purposes. A review of the annual market-to-book ratios for natural gas utilities since 1958 illustrates that market-to-book ratios equal to 1.0 are unusual, and market-to-book ratios greater than 1.0 are common. The average market-to-book ratio over the past 55 years is 1.6. Both regulators and investors are aware that market-to-book ratios exceed one. Even though regulators are aware of these market-to-book ratios, they still grant utilities rate increases. If the OAG-AUD were correct in its assessment of market-to-book ratios, regulators would grant lower rate increases and lower authorized returns on equity any time those ratios were above one.

87. The market-to book ratios for both the OAG-AUD's and MERC's comparison groups remained significantly above one for the period 2008-2013 and trend upward over the period 2009-2013. For the Department's comparison group, the average market-to-book ratio did not go below 1.719 during the period 2003 through 2013. According to the hypothesis

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[88] Ex. 18 at 20 (P. Moul Rebuttal).

[89] Ex. 18 at 21 (P. Moul Rebuttal); Ex. 161 at 28 (P. Chattopadhyay Direct).

[90] Ex. 161 at 9 (P. Chattopadhyay Direct); Ex. 164 at 3-8 (P. Chattopadhyay Rebuttal).

[91] Ex. 161 at 5, 9, 13-16 (P. Chattopadhyay Direct); Ex. 165 at 15-16 (P. Chattopadhyay Surrebuttal).

advanced by the OAG-AUD, for a period of at least 10 years, investors investing in the gas comparison group have received excessive returns (above normal returns or return above the cost of equity capital). Such a sustained excessive return over a long time period is not only counter to basic financial principles, but also common sense. Such excessive returns should have generated a run on gas utility stocks until the excessive profits were eliminated. It is clear this did not happen, as the market-to-book ratio continues to be significantly above one.[92] The financial literature cited by the OAG-AUD, when reviewed carefully, does not support the OAG-AUD's claim that the DCF analysis would produce an upward biased estimate of ROE when the market-to-book ratio is greater than one.[93] The OAG-AUD's own empirical studies produce unreasonably low ROEs when the market-to-book ratio equals one.[94]

88. With respect to MERC's rate of return analysis, MERC used a six-month average dividend yield for the period ending May 2013 for its DCF analysis. This resulted in a dividend of 3.91 percent. MERC then adjusted the dividend yield by the expected growth rate to arrive at an expected dividend yield of 4.02 percent.[95]

89. The Department disagreed with MERC's dividend yield calculation for two reasons. First, the Department objected to the use of month-end prices to calculate the dividend yields, arguing that given the stock market volatility, such a method may result in one particular price having too much influence on the six-month average dividend yield. Second, the Department argued that assuming current stock prices fully reflect all publicly available information, the use of long-term historical prices may result in biased dividend yields that reflect irrelevant information. The Department proposed substituting MERC's three-month average dividend yield for six-month average dividend yields.[96] The Department updated its dividend yield recommendations using closing prices from the most recently available 32-day period (03/14/2014-04/14/2014) and updated the annual dividend rates to the degree that they changed for any of the companies in the Department's comparison group. The Department's updated average dividend yields for the NGCG comparison group ranged from a low of 3.84 percent to a high of 3.88 percent and a mid-point of 3.86 percent.[97]

90. There is not a great deal of difference between MERC's dividend yield and the dividend yield calculated by the Department. The Department established a 3.94 percent mean yield within a range of 3.93 percent to 3.96 percent. MERC's updated dividend yield is 3.94 percent, prior to the forward-looking adjustment that brings MERC's final dividend yield to 4.05 percent.[98]

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92 Ex. 201 at 4 (E. Amit Rebuttal).

93 Ex. 201 at 5-7 (E. Amit Rebuttal).

94 Ex. 201 at 9 (E. Amit Rebuttal).

95 Ex. 200 at 48 (E. Amit Direct).

96 Ex. 200 at 48-49 (E. Amit Direct); Ex. 202 at 14 (E. Amit Surrebuttal).

97 Ex. 202 at 3 and Schedule (EA-S-2) (E. Amit Surrebuttal).

98 Ex. 18 at 10 and Schedule (PRM-2) (P. Moul Rebuttal).

91. The OAG-AUD disagreed with MERC's dividend yield calculation for two reasons. First, MERC used data from the previous six months as opposed to one month. According to the OAG-AUD, much of investors' expectations about how companies will fare in the future are captured in the most recently observed price and dividend data and data from fairly long historical periods are unlikely to reflect investors' current expectations. Second, MERC applied the projected growth in earnings to the observed dividend in a different manner than the OAG-AUD's traditional DCF recommendation. The OAG-AUD also noted that its and MERC's proxies are different. While the OAG-AUD's testimony relies on data from early 2014, MERC's calculation was based on data from December 2012 to May 2012.[99]

92. With respect to the growth rates used in MERC's rate of return analysis, based on the projected earnings per share provided by First Call, Zacks, Morning Star, SNL and Value Line, MERC concluded that an expected growth rate of five percent is a reasonable growth rate to use for the DCF analysis. The Department agreed with MERC's methodology of using the analysts' projected earnings per share growth rate, but proposed to substitute the analysts' average projected growth rate of 5.21 percent for the 5.00 percent proposed by MERC.[100] The Department updated its growth rates and determined that a projected growth rate of 5.27 percent is appropriate.[101]

93. There is not a great deal of difference between MERC's DCF growth rate and the mean growth rate calculated by the Department. MERC's DCF growth rate is 5.00 percent, which closely conforms to the Department's mean growth rate of 5.09 percent, as determined from the Department's range of 4.21 percent to 5.87 percent.[102]

94. The OAG-AUD disagreed with MERC's exclusive use of expected earnings growth rates for the growth component of MERC's DCF analysis. The OAG-AUD concluded that while theoretically use of earnings growth projection for the DCF growth component biases the estimate for cost of equity upward in an environment of market-to-book ratio being greater than one, on a practical level, relying on earnings projections also biases the DCF estimate upward. According the OAG-AUD, sole reliance on earnings growth is inherently unjust and unreasonable for ratepayers because it leads to unnecessary transfer of wealth from them to investors. The OAG-AUD also argued that the literature cited by MERC does not support the idea that investors use a single growth estimate when pricing a utility's stock. The OAG-AUD believes that it is appropriate to look at estimates individually for companies in the proxy to determine whether there are any outliers.[103]

95. The OAG-AUD also disagreed with the Department's conclusions regarding sustainable growth rates. Specifically, the OAG-AUD disagreed with the Department's

[99] Ex. 161 at 30 (P. Chattopadhyay Direct).

[100] Ex. 200 at 49-50 (E. Amit Direct).

[101] Ex. 202 at 7-9 (E. Amit Surrebuttal).

[102] Ex. 18 at 10 (P. Moul Rebuttal).

[103] Ex. 161 at 30-41 (P. Chattopadhyay Direct); Ex. 165 at 38 (P. Chattopadhyay Surrebuttal).

determination of sustainable growth rates, selection of companies for which the Department used TGDCF and the Department's reliance solely on projected earnings per share growth rates.[104]

96. MERC and the Department disagreed with the growth rates used by the OAG-AUD. Both MERC and the Department concluded that the analysts' projected Earnings Per Share ("EPS") growth rates are the best growth rates to use in a DCF analysis. In contrast, the OAG-AUD has concluded that some average growth rates that include EPS, Book Value Per Share ("BVPS") and Dividends Per Share ("DPS") growth rates in combination with the average EPS growth rate and the internal growth rate are better than average projected EPS growth rates.[105]

97. MERC questioned the OAG-AUD's exclusion of forecasts from Morningstar and SNL Financial, noting that a larger group of consensus forecasts is always better than a smaller sample because it will minimize the influence of outliers and potential biases.[106] Moreover, the Value Line forecasts used by the OAG-AUD must be discounted for the dividend and book value growth rates. There are problems with the Value Line per dividend share growth rate used by the OAG-AUD to calculate internal growth rates. The OAG-AUD relied on returns based on year-end book values, rather than average book values. Without an adjustment to convert the Value Line forecast returns from year-end to average book values, there is a downward bias in the results. MERC used a variant of the FERC's adjustment procedure to detect any downward bias in the figures reported by the OAG-AUD.[107]

98. The Department discounted the OAG-AUD's analysis and concluded that, over the long run, both the growth in BVPS and the growth in DPS are derived from the growth in EPS. While the short-run growth in DPS may be influenced by management's policy decisions, the long-run sustainable growth in DPS is solely driven by the growth in earnings. Moreover, the growth rate in BVPS is simply the mirror image of the growth rate in DPS. The Department concluded that the use of projected EPS growth rates is well supported by various financial studies and publications.[108]

99. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As a result, the CAPM computes a cost of equity by determining a risk-free rate of return, a measure of systematic risk called the Beta, and a market risk premium that is determined by subtracting the risk-free rate of return from the total return on the market of equities. Using the CAPM analysis, MERC computed a cost of common equity of 10.89 percent, after recognizing that the companies

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[104] Ex. 165 at 12-29 (P. Chattopadhyay Surrebuttal).

[105] Ex. 161 at 23-24 (P. Chattopadhyay Direct); Ex. 164 at 18-21 (P. Chattopadhyay Rebuttal); Ex. 165 at 31-32 (P. Chattopadhyay Surrebuttal).

[106] Ex. 18 at 26 (P. Moul Rebuttal).

[107] Ex. 18 at 26-30 (P. Moul Rebuttal).

[108] Ex. 201 at 12-19 (E. Amit Rebuttal); Ex. 202 at 30-35 (E. Amit Surrebuttal).

in MERC's proxy group are entitled to a size adjustment based upon their market capitalization.[109]

100. The Department's CAPM analysis was too low because the Department: 1) relied principally on historical yields on 20-year Treasury bonds for its risk-free rate of return; 2) did not use a leverage adjusted beta; and 3) ignored the size adjustment.

101. It's appropriate to include forward-looking data in the CAPM results because like all market models of the cost of equity, CAPM is exceptional. While the Department used a Treasury obligation with a more lengthy maturity (i.e., 20-year Treasury bonds), it failed to incorporate investor-expected yields in its analysis. The trend shows higher Treasury bond yields for the future that should be incorporated into the CAPM in order to conform to the specification of the model.[110]

102. MERC computed a leverage adjustment for both the DCF and CAPM analyses to reflect the fact that the market determined cost of equity reflects a level of financial risk that is different from the capital structure stated at book value. The leverage adjustment reflects the gap that must be bridged when using a market price in the DCF that relates to market value weights that differ from book value weights used in public utility rate setting.[111]

103. The Department rejected this adjustment, contending that it assumes that investors willingly pay too much for a stock when the return will be established on a book value capital structure rather than the market value of the utility's assets.[112] The Department took the position that neither the Modigliani-Miller, nor the Hamada equations used by MERC are applicable to the Company and the MERC Delivery Group because they contradict the fundamental principle that financial markets are efficient, i.e., the current stock prices fully reflect all publically available information. In addition, the Department argued that the Commission previously rejected MERC's proposed leverage adjustment in MERC's most recent rate case, Docket No. G007,011/GR-10-977, and MERC has provided no new arguments in the current proceeding to support its proposed adjustment.[113]

104. The Department's criticism does not apply because the leverage adjustment is a risk adjustment.[114] MERC's adjustment deals with the risk difference between the common equity ratio using market capitalization, the sole consideration of investors, and the book value common equity ratio used in utility rate cases. The Department's failure to compute a leverage adjustment in its DCF and CAPM analyses in this case understates the return on common equity that should be authorized for MERC.[115]

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[109] Ex. 17 at 37-41 (P. Moul Direct).

[110] Ex. 18 at 16 and Schedule 2 (PRM-2) (P. Moul Rebuttal).

[111] Ex. 18 at 13-15, 17 (P. Moul Rebuttal).

[112] Ex. 200 at 65-69 (E. Amit Direct); Ex. 202 at 21 (E. Amit Surrebuttal).

[113] Ex. 200 at 65-68 (E. Amit Direct); Ex. 202 at 21 (E. Amit Surrebuttal).

[114] Ex. 18 at 12-13 (P. Moul Rebuttal).

[115] Ex. 18 at 12-15 (P. Moul Rebuttal).

105. The OAG-AUD also rejected MERC's leverage adjustment. The OAG-AUD argued that the leverage adjustment proposed by MERC would encourage the stock price to deviate away from the book value, at the expense of retail customers and to the advantage of investors. The OAG-AUD concluded that MERC's proposed leverage adjustment emanates from the differences in the market price and the book value of a stock, fair value and the carrying value of debt, and the fair value and the carrying value of a preferred stock, respectively. According to the OAG-AUD, MERC's leverage adjustment is largely driven by the difference in the market-to-book ratio of common stock and the fair-to-carry ratio of debt.[116]

106. MERC's leverage adjustment does not depend on establishing or targeting any particular ratio of price to book value. The adjustment reflects the risk related to financial leverage and does not address the difference between expected return and opportunity cost rates, if any. MERC's leverage adjustment adds stability to the DCF return because the adjustment will increase or decrease as the dividend yield changes. MERC's adjustment is not a market-to-book ratio adjustment and does not alter the use of book values of common equity, preferred stock, and long-term debt in calculating the weighted average cost of capital. MERC's adjustment does not address any of the factors that would cause market prices to deviate from book value because it does not provide a return that supports any particular market-to-book ratio, high or low. MERC's adjustment solely addresses variations in financial risk, and is based on book values that are usually used in the rate setting process. The fact that the rate setting process uses the book value capital structure to calculate the weighted cost of capital, and the fact that investors understand that a utility's earnings are based in part on the allowed returns set in the rate case process, provides no basis to disregard MERC's leverage adjustment. MERC's leverage adjustment does not alter the procedure to calculate the weighted cost of capital, and the fact that sophisticated investors understand the rate setting process. Moreover, the market value of the capitalization can be accurately calculated and is not dependent on any other rate setting element. There is no market-to-book adjustment included in MERC's leverage adjustment.[117]

107. MERC also applied a size adjustment to the results of its CAPM. MERC's size adjustment is appropriate and is supported by extensive academic research that shows that a variety of factors explain the risk compensation required by investors that exceeds the risk-free rate of return (the yield on Treasury obligations). A well-known study conducted by Fama and French identified size as a separate factor that helps explain returns.[118]

108. Relevant research on the issue has identified the size of a firm as a separate factor that must be recognized in addition to the beta measure of systematic risk in explaining investor returns. These studies found that as the size of a firm decreases, its risk, and hence its required return, increases.[119]

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116 Ex. 161 at 5, 19-21 and Appendix 1, Equation C (P. Chattopadhyay Direct); Ex. 165 at 37 (P. Chattopadhyay Surrebuttal).

117 Ex. 18 at 32-34 (P. Moul Rebuttal).

118 Ex. 18 at 17-18 (P. Moul Rebuttal), citing "The Cross-Section of Expected Stock Returns," The Journal of Finance, June 1992.

119 Ex. 17 at 40-41 (P. Moul Direct).

109. The research indicates that stocks in lower deciles had returns in excess of those shown by the simple CAPM. In the case of low-cap market capitalization, a size premium of 1.23 percent is indicated by the 2013 Classic Yearbook for Stocks, Bonds, Bills and Inflation ("SBBI") published by Ibbotson Associates that is part of Morningstar. MERC adopted a more conservative size adjustment of 1.12 percent, which represents the mid-cap adjustment. Without this adjustment the academic research has demonstrated that the CAPM would understate the required return.[120]

110. The main point that the Department made in defense of excluding the size adjustment is that MERC's size is only one aspect of the Company's overall financial and business risk. The Department took the position that it is inappropriate to choose only one specific factor of the overall investment risk and argue that, due to this specific risk factor, MERC's required rate of return is higher than the rate of return for the comparison group. The Department noted that in MERC's most recent rate case, Docket No. G007,011/GR-10-977, the Commission rejected MERC's proposed size adjustment. According to the Department, MERC provided no new arguments in the current proceeding to support the proposed adjustment.[121]

111. The Fama and French study identifies size as a separate factor that helps explain returns and must be recognized in addition to the beta measure of systematic risk in explaining investor expected returns. The average size of the group covered by Value Line is the mid-cap group, which Value Line defines as companies with a market capitalization from $1 billion to $5 billion. As established in MERC's Direct Testimony and shown by the Morningstar 2014 Classic Yearbook, additional compensation is required for companies that are below the large cap category (defined by Morningstar as having less than $9.1 billion of market capitalization). A size adjustment is clearly required for the companies Value Line classifies as natural gas utilities.[122]

112. The OAG-AUD declined to adopt the size adjustment in the CAPM. The OAG-AUD took the position that not only is the evidence on small-firm effect not sufficiently persuasive, but even the basis for an upward adjustment to the allowed ROE, given the relative size of the proxy's capitalization relative to Integrys' capitalization, is questionable.[123]

113. The OAG-AUD's position is not appropriate in this case. The CAPM is commonly used in rate cases and is based on widely-accepted portfolio theory. There has been extensive academic research that shows that a variety of factors explain the risk compensation required by investors for the risk associated with small size. The Wong article cited by the OAG-AUD was authored twenty-one (21) years ago, and utilized data back to the 1960s. Enormous changes have occurred in the industry since the 1960s that have fundamentally changed the utility business. The Wong article notes that betas for non-regulated companies were higher than the betas of utilities. Lower betas do not invalidate the additional risk

[120] Ex. 17 at 36, 40-41 and Schedule 12 (PRM-1) (P. Moul Direct); Ex. 18 at 18 (P. Moul Rebuttal).

[121] Ex. 200 at 64, 67-68 (E. Amit Direct); Ex. 202 at 21 (E. Amit Surrebuttal).

[122] Ex. 18 at 17-18 (P. Moul Rebuttal).

[123] Ex. 161 at 49-50 (P. Chattopadhyay Direct).

associated with small size and beta is not the tool that should be employed to make a size determination.[124]

114. To determine the CAPM risk-free rate, MERC used the historical 30-year yields on Treasury notes and bonds. Specifically, MERC used a 3.75 percent risk-free rate of return for CAPM purposes, which considered not only Blue Chip forecasts, but also the recent trend in the yields on long-term Treasury bonds.[125]

115. The Department disagreed with MERC's risk free rate. The Department argued that the yield on 30-year Treasury bills includes significant interest risk premium and, therefore, does not represent a true risk-free yield. The Department further argued that current yields on long-term Treasury bills fully reflect current investors' expectations about the future economic and financial environment. Therefore, substituting Blue-Chip's forecast of future yields for current yields is inappropriate and simply introduces another element of uncertainty in the application of the CAPM. The Department proposed to account for MERC's risk-free yield by substituting the current September 2013 average yield on 20-year Treasury bonds (3.53 percent) for the 3.75 percent used by MERC.[126]

116. The Department inappropriately principally relied on historical yields on 20-year Treasury bonds for its risk-free rate of return. Just like all market models of the cost of equity, CAPM is exceptional. While the Department used a Treasury obligation with a more lengthy maturity (i.e., 20-year Treasury bonds), it failed to incorporate investor-expected yields in its analysis. The trend shows higher Treasury bond yields for the future that should be incorporated into the CAPM in order to conform to the specification of the model.[127]

117. The OAG-AUD argued that a 2.69 percent yield on ten-year Treasury notes should be used as the risk-free rate of return component of the CAPM. The OAG-AUD disagreed that the 30-year Treasury bond is an appropriate instrument to determine the risk free return and disagreed with MERC's reliance on forecasts as well as historical measures of yields to derive the risk free return. According to the OAG-AUD, the risk free return is best captured by short-term Treasury bills, but in recognition that utility rates are usually set for longer periods, longer-term bonds are used to capture the risk free rate when applying CAPM to estimate the cost of equity. The 10-year bond is the OAG-AUD's preferred metric for the risk free rate when conducting CAPM analysis for regulated companies because the OAG-AUD feels it strikes a reasonable balance between choosing a truly interest rate risk free instrument (like the shortest of the short term Treasury bills) and a consideration that regulated utility rates are usually set for longer terms than just a few months.[128]

118. MERC prefers to use longer term Treasury bond yields with a 30-year maturity. While the OAG-AUD may be correct that the 10-year Treasury note yield averaged 2.69 percent

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[124] Ex. 18 at 35-36 (P. Moul Rebuttal).

[125] Ex. 17 at 38-39 (P. Moul Direct).

[126] Ex. 200 at 31, 57-58 (E. Amit Direct); Ex. 202 at 15 (E. Amit Surrebuttal).

[127] Ex. 18 at 16 (P. Moul Rebuttal).

[128] Ex. 161 at 51 (P. Chattopadhyay Direct).

from January 30, 2014 to February 28, 2014, forecasts show that this rate is too low for the risk-free rate of return component of the CAPM for the 2014 test year and the rate effective period. Part of the increase can be attributed to the rise in yields, which in turn can be attributed to the tapering of the Federal Open Market Committee's last quantitative easing. It is for this reason that MERC used both a forecast and longer-term 30-year Treasury yield that produces a 4.50 percent risk-free rate of return in the update of its CAPM cost rate.[129]

119. With respect to MERC's derivation of the market-risk premium, the OAG-AUD disagreed with MERC's reliance on historical data to determine the risk premium approach to measure the Value Line risk premium, as well as MERC's mixing of market risk premiums from two distinct sets of companies to derive a solitary measure of risk premium. The OAG-AUD's preferred approach is to rely only on the DCF based estimates of market risk premiums and individually estimate the returns on equity using Value Line and S&P information.[130] MERC does not object to the 9.08 percent market premium used by the OAG-AUD because the market premium result is higher than the market premium result from the procedures MERC used.[131]

120. The RP analysis determines the cost of equity by adding to corporate bond yields a premium to account for the fact that common equity capital is exposed to greater investment risk than debt capital. MERC's RP analysis utilized the Moody's index of A-rated Public Utility Bonds along with the forecast of interest rates provided in the Blue Chip Financial Forecast.[132] For an equity risk premium, MERC looked to the SBBI (i.e. Morningstar) Classic Yearbook to identify the equity risk premium that is aligned with the prospective level of interest rates.[133] The result of this methodology produced an updated ROE of 12.14 percent.[134]

121. The Department took the position that MERC used the wrong methodology to estimate the yield on A-rated utility bonds and, therefore, MERC's proposed yield was biased upward. The Department further discounted MERC's RP analysis because it was conducted with historical data and used the wrong risk premium.[135] MERC's risk premium was established with historical data. However, using this historical data, MERC obtained results that were positioned to account for conditions expected for the future. The data presented by MERC shows that the equity risk premium varies with the level of interest rates. In order to recognize the dynamic nature of the equity risk premium and to fit that premium to future market fundamentals, MERC performed an analysis to align the historically developed equity premium with the expected level of interest rates. In MERC's rebuttal update, MERC reduced the equity risk premium to recognize the increase in interest rates that has occurred since MERC's Direct Testimony was

129 Ex. 18 at 36-37 and Schedule 1 (PRM-2) (P. Moul Rebuttal).

130 Ex. 161 at 46-53 (P. Chattopadhyay Direct).

131 Ex. 18 at 37 (P. Moul Rebuttal).

132 Ex. 17 at 33-34 (P. Moul Direct).

133 Ex. 17 at 34-36 (P. Moul Direct).

134 Ex. 18 at 36 (P. Moul Rebuttal).

135 Ex. 200 at 52-55 (E. Amit Direct); Ex. 202 at 14-15 (E. Amit Surrebuttal).

prepared. The value of MERC's method, which considers the level of interest rates, is that it allows the RP approach to conform to a forward-looking cost of equity.[136]

122. The OAG-AUD elected not to use the RP approach to determine the cost of equity. According to the OAG-AUD, the RP approach is inappropriate because RP is largely not forward-looking and reliance on historical data exposes the method to considerable subjective manipulation. Also, according to the OAG-AUD, RP is conceptually similar to the CAPM method as it also models a higher return for higher risk and purports to model the risk premium associated with equity capital over a risk-free debt instrument.[137] Although the OAG-AUD does not support the use of an RP analysis, it raises multiple concerns with the RP methodology used by MERC.[138]

123. The CE approach determines the equity return based upon results from non-regulated companies. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the CE standard. The firms selected for the CE approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.[139]

124. To implement the CE approach, MERC selected non-regulated companies from the Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Delivery Group. These screening criteria were based upon the range as defined by the rankings of the companies in MERC's Delivery Group. MERC used both historical and realized returns and forecasted returns for non-utility companies. It is appropriate to consider a relatively long measurement period in the CE approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and the CAPM, the results of the CE method can be applied directly to the book value capitalization. MERC calculated a CE result of 11.70 percent.[140]

125. The Department disagreed with MERC's CE analysis. While the Department conceded that MERC used appropriate screens to select the comparison group, the Department concluded that the results of MERC's analysis clearly indicated that MERC's selected group includes many companies that are not risk comparable to the investment risks in MERC's Delivery Group.[141]

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136 Ex. 18 at 19 and Schedule 8 (PRM-2) (P. Moul Rebuttal).

137 Ex. 161 at 53 (P. Chattopadhyay Direct).

138 Ex. 161 at 53-55 (P. Chattopadhyay Direct).

139 Ex. 17 at 42-43 (P. Moul Direct).

140 Ex. 17 at 43-45 and Schedule 13 (PRM-1) (P. Moul Direct). The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank.

141 Ex. 200 at 59 (E. Amit Direct).

126. The OAG-AUD found MERC's CE proxy to be inappropriate. According to the OAG-AUD, the overly subjective nature of forming a proxy for a regulated company using non-regulated companies persuades it not to consider the CE approach. In the OAG-AUD's opinion, reliance on the DCF approach that carefully focuses on deriving a proxy for MERC in determining a forward looking estimate of the cost of equity is significantly superior to any implementation of the CE approach that relies not only on historical data from non-utility companies, but also bases its estimate on historical and forecasted accounting returns on common equity that are poor proxies for the true cost of equity.[142]

127. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon an investor's assessment of overall risk.[143]

128. MERC faces risk factors that cannot be quantified but must be accounted for in order to provide a reasonable opportunity for MERC to achieve its cost of capital. These risks are: the risks that all gas utilities face arising from competition, economic regulation, the business cycle, and customer usage patterns; MERC's high construction expenditures; and MERC's approximately 79 percent total throughput to large volume customers that have the ability to bypass the Local Distribution Company ("LDC") system.[144]

129. MERC faces risk factors that can be quantified as compared to the S&P Public Utilities, an industry-wide proxy group including other regulated utilities, and MERC's proxy group.[145] While there were instances in which MERC did not have an increased risk, there were a number of counts in which MERC's risk was much higher than the Company's proxy group.

130. MERC is much smaller than the average size of the Company's proxy group and the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionally greater impact on a smaller firm. MERC also experienced poor earned returns and higher variability than the S&P Public Utilities and the Company's proxy group, which signifies higher risk for MERC. The five-year operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income) for MERC is higher than the S&P Public Utilities and the Company's proxy group, which indicates greater risk. MERC had a lower level of interest coverage (the multiple by which available earnings cover fixed charges, such as interest expense) than the S&P Public Utilities and the Company's proxy group, which signifies higher credit risk for the company.[146]

131. MERC's cost of equity recommendation is conservative due to the higher risk characteristics of MERC. Each of these risk factors point to a return for the Company that must be greater than the results indicated by the proxy group analysis. That is to say, results taken

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142 Ex. 161 at 55-56 (P. Chattopadhyay Direct).

143 Ex. 17 at 12 (P. Moul Direct).

144 Ex. 17 at 8-11 (P. Moul Direct).

145 Ex. 17 at 12 (P. Moul Direct).

146 Ex. 17 at 12-17 (P. Moul Direct).

from MERC's proxy group will understate the required return for the Company because it has a higher risk.[147]

132. Based on an analysis of MERC's risk indicators, the Department concluded that there is not a valid basis to conclude that MERC's investment risk is greater than MERC's Delivery Group investment risk. The Department disagreed with the risk indictors used by MERC. The Department stated that, as a general matter, MERC should have used a macro, not micro, analysis.[148] Regarding the specific factors used by MERC, the Department concluded that: adjusting for risk based on the high percentage of revenue received by MERC from large volume customers is inappropriate; using the averages for the Delivery Group tends to mitigate the impact of weather and a more appropriate measure should be based on weather-normalized data; to the degree that the weak measures for MERC are the result of MERC's own inefficient operations, MERC should not be rewarded with a higher allowed ROE; and the historical values of the risk indicators used by MERC may not be good indicators of MERC's investment risk.[149]

133. MERC maintains its position that the Company's cost of equity recommendation is conservative due to the higher risk characteristics of MERC and the fact that results taken from the Delivery Group will understate the required return for MERC. The Department has recognized that MERC has more financial risk than the NGCC used in the Department's cost of equity analysis.[150]

134. The opportunity to achieve a reasonable ROE represents a direct signal to the investment community whether to expect that regulatory oversight of the utility will result in the utility generating sufficient earnings to enable investors to earn a rate of return that is reasonable in light of other investment opportunities. To obtain new capital and retain existing capital the rate of return on common equity must be high enough to satisfy investors' requirements.[151]

135. Based on the analysis of returns established in other natural gas regulatory proceedings, the returns that investors expect gas utilities to achieve, and the general state of the capital markets, the Commission should not provide MERC with an equity return that is lower than 10 percent.[152] Anything lower may jeopardize MERC's ability to attract capital, and in turn, meet its service responsibilities to customers.

136. MERC presented a thorough analysis that has used multiple financial models and numerous data-based checks on the reasonableness of potential returns on common equity. MERC's analysis supports a ROE of 10.75 percent in this case, and also illustrates the ways that the Department and the OAG-AUD ignored key considerations that understate MERC's cost of equity. MERC's analysis, therefore, provides a better basis to determine a return on common equity for MERC.

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[147] Ex. 17 at 17 (P. Moul Direct); Ex. 18 at 3-5 (P. Moul Rebuttal).

[148] Ex. 200 at 60-61 (E. Amit Direct).

[149] Ex. 200 at 61-63 (E. Amit Direct); Ex. 202 at 16-17 (E. Amit Surrebuttal).

[150] Ex. 18 at 4-5 (P. Moul Rebuttal).

[151] Ex. 18 at 6-8 (P. Moul Rebuttal).

[152] Ex. 18 at 7-8 (P. Moul Rebuttal).

137. The ALJ finds that MERC's authorized return on common equity should be 10.75 percent.

4. Flotation Costs

138. In general, DCF results must be adjusted to allow for the cost of issuing new shares of common stock without causing dilution. Due to issuance costs, the price paid by an investor for a new share of common stock is higher than the price per share received by the company. These issuance costs must be recognized by adjusting the required rate of return. This adjustment is appropriate even if no new issuances are planned in the near future because failure to allow such an adjustment may deny MERC the opportunity to earn its required rate of return in the future and such a denial is contradictory to the purpose of rate of return regulation.[153]

139. MERC proposed to include a flotation cost adjustment of 0.14 percent based on MERC's updated cost of equity analysis and based on a value of flotation costs of 3.9 percent.[154]

140. MERC and the Department agreed that a flotation cost must be included in the DCF analysis and the Department agreed with MERC's flotation cost of 3.9 percent for the MERC Delivery Group. However, the Department disagreed with MERC's calculation of flotation cost adjustment.[155] In contrast to MERC's approach to determining flotation cost adjustment, the Department applied the 3.9 percent value of flotation costs to the dividend yield component of the DCF, resulting in 0.15 percent of return applicable to flotation costs.[156]

141. While the procedures used by MERC and the Department differ, the end result is remarkably similar. MERC's flotation cost adjustment adds fourteen basis points (i.e., 0.14%) to the cost of equity, while the Department's calculation adds fifteen basis points (i.e., 0.15%) to the cost of equity.[157]

142. The OAG-AUD objected to adjusting the ROE for flotation costs for two reasons: 1) when the market-to-book ratio is greater than one the DCF produces an upward biased ROE estimate and such ROE already accounts for flotation costs; and 2) investors buy new shares of stock, knowing that the price they pay is higher than the revenues per share received by MERC from the sale of new shares. Therefore, according to the OAG-AUD, by purchasing new shares, investors reveal that the return on book value is at least equal to investors' required return.[158]

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[153] Ex. 200 at 26-27 (E. Amit Direct).

[154] Ex. 17 at 31-32 and Schedule (PRM-1) (P. Moul Direct); Ex. 18 at 38 (P. Moul Rebuttal).

[155] Ex. 18 at 38 (P. Moul Rebuttal); Ex. 200 at 50 and Schedule (EA-14) (E. Amit Direct); Ex. 202 at 14 (E. Amit Surrebuttal).

[156] Ex. 200 at 26-27 and Schedules (EA-7 and EA-14) (E. Amit Direct); Ex. 201 at 24-26 (E. Amit Rebuttal).

[157] Ex. 18 at 10, 38 and Schedule 1 (PRM-2) (P. Moul Rebuttal).

[158] Ex. 161 at 43-45 (P. Chattopadhyay Direct); Ex. 164 at 25-27 (P. Chattopadhyay Rebuttal); Ex. 165 at 33-36, 38 (P. Chattopadhyay Surrebuttal); Ex. 200 at 24 (E. Amit Direct); Ex. 202 at 35-36 (E. Amit Surrebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 182 (P. Chattopadhyay) and 202-204 (E. Amit) (Doc. ID No. 20145-99937-01).

143. The OAG-AUD's failure to modify its DCF results for flotation costs resulted in an understatement of the required rate of return on common equity. The OAG-AUD's position concerning flotation costs is inconsistent with the Value Line forecasts that show that natural gas companies will be issuing new common stock in the future. In addition, the OAG-AUD included external financing growth in its DCF analysis, which mandates a flotation cost adjustment. When utilities obtain new equity as represented by external financing growth factor, there are flotation costs associated with obtaining that new equity. Moreover, the industry has historically issued significant quantities of new equity that had flotation costs. The OAG-AUD's argument that its proposed rate of return provides an adequate cushion to cover flotation costs is inaccurate. Flotation cost allowance is designed to account for the fact that the underwriter's discount/commission and the utility's out-of-pocket expense must be paid before the utility can invest the net proceeds from a common stock issuance into the rate base on which it earns a return. These costs exist regardless of the market-to-book ratio for any given company and are no different than the recovery of issuance expenses associated with selling long-term debt to investors. Moreover, the Commission has previously recognized a flotation cost adjustment when it has set a utility equity return. There is nothing unusual about including a flotation cost in the cost of equity in a rate case.[159]

144. Because the DCF analysis does not produce an upward biased ROE estimate, the DCF results must still be adjusted for flotation costs. Moreover, it would be inappropriate to disallow a legitimate cost to MERC to compensate for some other alleged excess revenue unrelated to flotation costs. To the degree that utilities are allowed to recover flotation cost, the allowed rates of return on book equity inherently reflect the flotation cost adjustment. Investors buying new shares of stock would buy them only if they expected to earn their required rate of return. However, absent allowance for flotation costs, existing shareholders would not be able to receive their required rate of return. Thus, the ROE must include a flotation cost adjustment and the OAG-AUD has provided no reasonable arguments to support disallowance of flotation costs.[160]

145. The Commission frequently approves cost of equity recommendations adjusted for flotation costs in rate cases. For example, the Commission recently approved the inclusion of a flotation cost adjustment of 16 basis points in the 2013 *Center Point Energy* natural gas rate case;[161] a flotation cost adjustment of 13 basis points in the 2012 *Northern States Power* electric service rate case;[162] a flotation cost adjustment of 15 basis points in the 2011 *Northern States*

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[159] Ex. 18 at 31, 38-39 and Schedule 6 (PRM-2) (P. Moul Rebuttal). The Commission recognized flotation cost adjustments of 0.23 percent in the rate case for Northern States Power (Docket No. G002/GR-09-1153), 0.20 percent in the rate case for CenterPoint Energy (Docket No. G008/GR-08-1075), and a 0.17 flotation cost adjustment in MERC's last rate case (Docket No. G007,011/GR-10-977) where the final surrebuttal evidence offered by the DOC showed flotation costs of 0.17 percent (i.e., 9.41% - 9.24%).

[160] Ex. 200 at 25 and Schedule (EA-14) (E. Amit Direct).

[161] *In the Matter of an Application by CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas For Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G-008/GR-13-316, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 31-32 (June 9, 2014) (Doc. ID No. 20146-100252-01).

[162] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-12-961, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 11-12 (Sept. 3, 2013) (concurring with the ALJ findings regarding ROE, which included the basis points finding in paragraph 365 of the July 3, 2013 order) (Doc. ID No. 20139-90902-01).

Power electric service rate case;[163] a flotation cost adjustment of 18 basis points in 2011 Interstate Power & Light electric service rate case;[164] a flotation cost adjustment of 20 basis points in the 2011 *Otter Tail Power Company* electric service rate case;[165] a flotation cost adjustment of 23 basis points in the 2009 *Northern States Power* natural gas rate case;[166] and a flotation cost adjustment of 20 basis points in the 2008 *Center Point Energy* natural gas rate case.[167]

146. MERC and the Department have demonstrated that a flotation cost adjustment is necessary for MERC to have a reasonable opportunity to earn its required rate of return.

147. The ALJ finds that MERC's cost of equity should be adjusted by 14 basis points to account for flotation costs.

B. MERC's Test Year Sales Forecast

148. MERC forecasted sales and fixed charge counts in the spring of 2013 using actual data from January 2007 through January 2013, and revenues were calculated based on this sales forecast.[168] To develop its forecast, MERC used MetrixND, a statistical software package that considers billing sales, price, structural changes, appliance saturation and efficiencies trends. MetrixND then imposes a model structure through a Statistical Adjusted End-Use ("SAE") specification.[169]

149. The Department recommended an alternative test year sales forecast.[170] Based on the alternative test year sales forecast, the Department recommended a total test year revenue figure of $266,151,734, which resulted in an increase to test year revenue of approximately $8,965,271 over MERC's originally filed revenue estimate of $257,186,463. After accounting

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[163] *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-10-971, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 10-11 (May 14, 2012) (adopting the settlement regarding basis points as described in paragraphs 87 and 88 of the Feb. 22, 2012 ALJ order) (Doc. ID No. 20125-74691-01).

[164] *In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-001/GR-10-276, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 8-12 (Aug. 12, 2011) (Doc. ID No. 20118-65311-01).

[165] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-10-239, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 42-43 (Apr. 25, 2011) (concurring with the ALJ findings regarding ROE, which included the basis points finding in paragraph 388 of the Feb. 14, 2011 order) (Doc. ID No. 20114-61715-01).

[166] *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G002/GR-09-1153, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 27 (Dec. 6, 2010) (Doc. ID. No. 201012-57199-01).

[167] *In the Matter of an Application by CenterPoint Energy for Authority to Increase Natural Gas Rate in Minnesota*, Docket No. G008/GR-08-1075, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (Jan. 11, 2010) (Doc. ID No. 20101-45867-01).

[168] Ex. 19 at 8 (S. DeMerritt Direct).

[169] Ex. 38 at 5-11 (H. John Direct).

[170] Ex. 212 at 5 (L. Otis Direct).

for increased natural gas cost expenses and Conservation Cost Recovery Charge ("CCRC") revenues, the Department's total net revenue adjustment is approximately $1,965,865 greater than MERC's originally filed revenue estimate.[171]

150. MERC accepted the Department's recommended alternative test year sales forecast because it benefitted from having a full year of calendar year 2013 data, which was not available to MERC at the time the Company prepared its test year sales forecast.[172] Based on MERC's acceptance of the Department's alternative test year sales forecast, the Department determined that there were no issues related to test year sales forecasting that remain in dispute between MERC and the Department.[173]

151. Although MERC agreed to use the Department's alternative sales forecast in this proceeding, MERC does not agree that its forecasting model is inappropriate.[174] MERC and the Department have agreed to work together to address future sales forecasting methodology.[175]

152. The Department and MERC agreed that MERC provided spreadsheets that fully linked together all raw data and inputs for MERC's sales forecast.[176]

153. The ALJ concludes that the sales forecast agreed to by MERC and the Department is reasonable and should be used for purposes of setting rates in this proceeding.

154. MERC's original cost of gas was updated using NYMEX data from May 15, 2013, as described in the Base Cost of Gas filing in Docket No. G011/MR-13-732.[177] MERC's cost of gas was updated a second time on April 15, 2014 using NYMEX data from March 17, 2014, as described in the Base Cost of Gas filing in Docket Nos. G011/GR-13-617 and G011/MR-13-732.[178] The Department noted that MERC did not update its base cost of gas calculations with the Department forecast which the Company had agreed to in this docket. The Department brought this issue to MERC's attention and MERC provided the Department with updated calculations that included the agreed-upon forecast figures. The Department agreed with MERC's updated calculations and recommended that MERC's final rates be based on the level of commodity gas costs based on the Department's updated test year sales figure.[179]

155. The ALJ finds that MERC's final rates be based on the level of commodity gas costs based on the Department's updated test year sales figure.

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171 Ex. 212 at 28-29, 32 and Schedule (LBO-11) (L. Otis Direct).

172 Ex. 39 at 2, 8 (H. John Rebuttal).

173 Ex. 214 at 1 (L. Otis Surrebuttal).

174 Ex. 39 at 8 (H. John Rebuttal).

175 Evidentiary Hearing Transcript (May 13, 2014) at 106-108 (H. John) and 207-209 (L. Otis) (Doc. ID No. 20145-99937-01).

176 Ex. 39 at 5-7 (H. John Rebuttal); Ex. 214 at 3-4 (L. Otis Surrebuttal).

177 Ex. 19 at 8 (S. DeMerritt Direct).

178 Ex. 24 at 29 (S. DeMerritt Rebuttal).

179 Evidentiary Hearing Transcript (May 13, 2014) at 208-209 (L. Otis) (Doc. ID No. 20145-99937-01).

C. MERC's Overall Employee Benefit Cost Increase

156. MERC developed its 2014 test year employee benefits requested for rate recovery in four categories:

> (1) 2014 costs that are not requested for rate recovery in 2014;
>
> (2) forecasted 2014 costs that were estimated by MERC based on preliminary results and trend information from MERC's actuary;
>
> (3) forecasted 2011 costs that were determined by inflating 2012 actual costs; and
>
> (4) forecasted 2014 costs that were determined through actuarial analysis.

The first category contains costs related to MERC's share of Integrys Business Support's ("IBS") current costs related to non-qualified benefits. The second category contains MERC's dental benefits, medical benefits, and IBS benefits that are billed to MERC. The third category contains a number of sub-accounts that have been referred to in testimony as MERC's "other employee benefits." The fourth category contains the pension benefit costs for MERC and IBS.[180]

157. The Department recommended adjusting 2014 employee benefit costs determined by actuarial analysis by updating the measurement date and plan asset value date, and changing the discount rate assumption, making it equal to the expected return on plan assets.[181] Other than that, the Department did not recommend any changes to any of the other employee benefit expenses as compared to MERC's initial filing in this case.[182]

158. MERC agreed with the Department that actuarially determined costs should be based on the most recent and accurate data available.[183] MERC provided an actuarial analysis updated as of December 31, 2013 for the pension and post-retirement life plans, and updated as of March 1, 2014, for the post-retirement medical plan. MERC recommended that the updated actuarial analyses be included in the calculation of the 2014 test year revenue requirement.[184] The Department did not object to MERC's proposal.[185]

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180 Ex. 26 at 3-15 and Schedules (CMH-1 and CMH-2) (C. Hans Direct).

181 Ex. 217 at 29-30 (M. St. Pierre Direct).

182 Ex. 26 at 4 (C. Hans Rebuttal).

183 Ex. 27 at 5 (C. Hans Rebuttal).

184 Ex. 27 at 5-7 (C. Hans Rebuttal).

185 Ex. 219 at 25-26 (M. St. Pierre Surrebuttal).

159. MERC noted that the expected return on plan assets in the actuarially determined benefit costs for the 2014 test year was 8.00 percent and the Department did not recommend any changes to that percentage.[186]

160. The Department concluded that MERC's discount rates may be too low because they were less than the expected return on plan assets. The Department cited Xcel Energy's 2012 rate case (Docket No. E002/GR-12-961) as support for its assertion that the discount and expected return on plan asset used to determine test year pension expense should be equal.[187]

161. Each of the two assumptions, the discount rate and the expected return on plan assets are independently determined in accordance with Generally Accepted Accounting Principles ("GAAP") and the discount rates for each plan are based on the specific expected benefit payments for the plan. Moreover, in MERC's last rate case the ALJ found that the discount rate should be set at 6.25 percent and the expected return on plan assets at 8.50 percent, as recommended by the Department.

162. Regarding Xcel's 2012 rate case cited by the Department, the ALJ's decision in that case was plan specific and Xcel's plan does not resemble MERC's plan. MERC proposed that the Company's updated actuarial analyses, using the discount rates supported by GAAP, be included in the calculation of the 2014 test year revenue requirement.[188]

163. The ALJ finds that MERC's updated actuarial analyses, using the discount rates supported by GAAP, should be included in the calculation of the 2014 test year revenue requirement.

D. Pension Expense

164. In Docket No. G007,011/GR-10-977, the Commission required MERC to fully support the reasonableness of having ratepayers pay for 100 percent of its pension obligation in this rate case.[189]

165. In 2008, MERC announced it was beginning an orderly transition from a defined benefit pension plan to a defined contribution plan. As part of that transition, the pension plan that had been offered to Administrative employees was closed to new entrants. At the same time, the Company, through the collective bargaining process, commenced negotiating the closing of the pension plan with the unions that represented a portion of MERC's work force. There are no longer any open pension plans at MERC. However, there are pension obligations that do remain in place for those employees who participated in the plans before they were closed. MERC believes it is reasonable to continue to have those previously promised

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[186] Ex. 27 at 8 (C. Hans Rebuttal).

[187] Ex. 217 at 30-31 (M. St. Pierre Direct).

[188] Ex. 27 at 4-12 (C. Hans Rebuttal).

[189] Ex. 13 at 14 (N. Cleary Direct).

obligations recovered through rates as those obligations arose from a time when ratepayers were supportive of pension programs for public utility employees.[190]

166. The Commission has emphasized that the goal of ratemaking is to reflect actual costs as accurately as possible in order to allow utilities recovery of their reasonable operating expenses. To do so, the Commission has stated that it is important to find the most accurate cost-measurement tools available. Which tools are the most accurate is a fact-specific inquiry, and the answers vary from case to case.[191]

167. On January 27, 2014, Towers Watson, MERC's actuary, completed an updated actuarial analysis for MERC's 2014 test year pension expense and found that MERC will have a 2014 pension expense of $126,771, which MERC included as its 2014 test-year pension expense.[192]

168. There are four components of the Statement of Financial Accounting Standards ("SFAS") No. 87 pension expense: (1) service cost; (2) interest cost; (3) expected earnings on plan assets; and (4) amortization of gains and losses, prior service costs, and any transitional amounts.[193]

169. In order to calculate the plan's total benefit obligation and annual SFAS No. 87 expense, the actuary uses a number of assumptions including: (1) mortality tables; (2) retirement rates for MERC; (3) anticipated salary increases; (4) expected return on plan assets; and (5) a discount rate.[194]

170. These assumptions are determined by MERC with the concurrence of Towers Watson in accordance with GAAP. The assumptions are then reviewed for reasonableness by MERC's external auditor, Deloitte and Touche.[195]

171. MERC's annual pension expense was $1,212,062 in 2012 and is projected to be $126,771 for 2014. Also included in pension expense for both 2012 and 2014 is an amortization of $474,223 per year as authorized by the Commission in Docket No. G-007,011/M-06-1287 on July 30, 2007 for pension and other post-retirement benefits acquired from Aquila.[196]

172. MERC has taken steps to help control pension costs. The most significant change was a shift from the traditional defined benefit pension plan to a defined contribution model

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[190] Ex. 13 at 14 (N. Cleary Direct).

[191] *See Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket E-015/GR-09-1151, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 26 (November 2, 2010); *Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota*, Docket E-017/GR-10-239, FINDINGS OF FACT, CONCLUSIONS AND ORDER at 25 (April 25, 2011).

[192] Ex. 26 at 11 and Schedule (CMH-1) (C. Hans Direct); Ex. 27 at 5 and Schedule (CMH-1) (C. Hans Rebuttal).

[193] Ex. 26 at 9-10 and Schedule (CMH-1) (C. Hans Direct).

[194] Ex. 26 at 10-11 and Schedule (CMH-1) (C. Hans Direct).

[195] Ex. 26 at 9, 11 (C. Hans Direct).

[196] Ex. 26 at 11 (C. Hans Direct).

integrated with the 401K plan. Also, effective January 1, 2008, the pension plan was closed to administrative (non-union) new hires.[197]

173. The Department does not take a position on MERC's change from a defined benefit to a defined contribution plan for union or non-union employees.[198]

174. The Department had concerns with the reasonableness of the assumptions that were used in MERC's 2014 test year actuarial determined pension expense.[199]

175. Because the Department does not believe that MERC's 2014 pension expenses are reasonable it recommended a reduction in MERC's test year pension expense of $1,350,012. The Department also recommended that plan asset values be updated to reflect the balance on December 31, 2013 and MERC's test year actuarially determined costs also be based on equal discount and long-term growth rates (i.e., 8% discount rate and long-term growth).[200]

176. MERC agreed with the Department that actuarially determined costs should be based on the most recent and accurate data available.[201] MERC provided an actuarial analysis updated as of December 31, 2013 for the pension plan. MERC recommended that the updated actuarial analyses be included in the calculation of the 2014 test year revenue requirement.[202]

177. The Department did not object to MERC's proposal.[203]

178. MERC disagreed with the Department's recommendation to set the discount rate equal to the expected return on plan assets. Each of the two assumptions, the discount rate and the expected return on plan assets, are independently determined in accordance with GAAP and the discount rates for each plan are based on the specific expected benefit payments for the plan. MERC proposed that the Company's updated actuarial analyses, using the discount rates supported by GAAP, be included in the calculation of the 2014 test year revenue requirement.[204] The 2014 test year costs proposed by MERC are now known with a certainty; they are not an estimate.[205]

179. MERC has demonstrated that its actuarial determined 2014 test year pension benefit expense is reasonable and most accurately reflects the cost that MERC will incur in the test year and until its next rate case.

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[197] Ex. 26 at 11-12 (C. Hans Direct).

[198] Ex. 217 at 27 (M. St. Pierre Direct).

[199] Ex. 217 at 29-34 (M. St. Pierre Direct).

[200] Ex. 217 at 34 (M. St. Pierre Direct).

[201] Ex. 27 at 5 (C. Hans Rebuttal).

[202] Ex. 27 at 5-7 (C. Hans Rebuttal).

[203] Ex. 219 at 25-26 (M. St. Pierre Surrebuttal).

[204] Ex. 27 at 4-12 (C. Hans Rebuttal).

[205] Evidentiary Hearing Transcript (May 13, 2014) at 55 (C. Hans) (Doc. ID No. 20145-99937-01).

180. The ALJ finds that MERC's test year pension expense should be $126,771 for 2014.

E. Other Actuarially Determined Benefits

181. MERC did not seek recovery of non-qualified employee benefit costs for Pension Restoration Plan (Account 926210) and Supplemental Executive Retirement Plan ("SERP") (Account 926220).[206]

182. Because MERC did not seek recovery of the expense portion of these accounts, the Department recommended removal of the related rate base portion of the accounts (Accounts 228300, 228305, 228310, and 242072).[207] MERC agreed to the removal of these accounts.[208]

183. MERC has proposed to include test year post-retirement medical plan expense of $278,962 and post-retirement life insurance expense of $(5,732).[209]

184. The Department had concerns with the reasonableness of the initial assumptions that were used in MERC's 2014 test year actuarially determined post-retirement medical and insurance plans and recommended that MERC's test year actuarially determined costs be based on a discount rate set equal to the long-term growth rate and also that plan asset values be updated to reflect the balances as of December 31, 2013.[210]

185. MERC agreed with the Department that actuarially determined costs should be based on the most recent and accurate data available.[211] MERC provided an actuarial analysis updated as of December 31, 2013 for the post-retirement life plan. MERC recommended that the updated actuarial analyses be included in the calculation of the 2014 test year revenue requirement.[212]

186. The Department did not object to MERC's proposal.[213]

187. MERC disagreed with the Department's recommendation to set the discount rate equal to the expected return on plan assets. MERC explained that each of the two assumptions, the discount rate and the expected return on plan assets are independently determined in accordance with GAAP and the discount rates for each plan are based on the specific expected benefit payments for the plan. MERC proposed that the Company's updated actuarial analyses,

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[206] Ex. 26 at 3-4 (C. Hans Direct).

[207] Ex. 217 at 7 (M. St. Pierre Direct).

[208] Evidentiary Hearing Transcript (May 13, 2014) at 56 (C. Hans) (Doc. ID No. 20145-99937-01); Ex. 27 at Schedule (CMH-4) (C. Hans Rebuttal).

[209] Ex. 27 at Schedule (CMH-1) (C. Hans Rebuttal).

[210] Ex. 217 at 28-34 (M. St. Pierre Direct).

[211] Ex. 27 at 5 (C. Hans Rebuttal).

[212] Ex. 27 at 5-7 (C. Hans Rebuttal).

[213] Ex. 219 at 25-26 (M. St. Pierre Surrebuttal).

using the discount rates supported by GAAP, be included in the calculation of the 2014 test year revenue requirement.[214]

188. The Department accepted MERC's updated post-retirement medical costs of $278,962 because the update provides the only available evidence that reflects the decrease in test year costs due to the change in post-retirement medical plans. The Department did not accept MERC's position to use a discount rate lower than the expected return on assets. The Department recommended that the Commission require MERC to reduce rate base by $139,077 for MERC's updated reduction in post-retirement medical expense and for MERC's share, plus IBS's share, for a total decrease of $140,720 in post-retirement medical expense.[215]

189. The Department did not change its recommendation with respect to MERC's post retirement life insurance expense since the Department used the most recent actuarial update for the 2014 test year in its calculation. The Department continues to recommend an increase of $3,853 for MERC's post retirement life insurance expense.[216]

190. The ALJ finds that MERC's actuarial determined 2014 test year post-retirement life insurance expense is reasonable and most accurately reflects the cost that MERC will incur, in the test year and until its next rate case.

F. Test Year Non-Fuel O&M Expense Methodology

191. This proceeding is based on a test year of 2014 for MERC's operations. To determine its test year non-fuel O&M expense, MERC used its actual 2012 non-fuel O&M costs, applied inflation factors for 2013 and 2014, and applied seventeen known and measurable ("K&M") adjustments to arrive at its test year or projected 2014 non-fuel O&M expenses.[217] Specifically, MERC has identified the following K&M adjustments to O&M expense:

> 1) increased costs from IBS-Customer Relations, related to increased third party costs from Vertex, the company that is under contract to provide MERC's third-party customer service functions (customer call center, dispatch, billing, and payment processing, etc.), and implementation of the Integrys Customer Experience ("ICE");
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> 2) increased costs associated with vacant positions that existed at MERC and IBS during 2012;
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> 3) increased costs associated with Uncollectible Expense;
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> 4) increased costs associated with a Sewer Laterals Project;
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> 5) increased costs associated with Gate Station Upgrades;

[214] Ex. 27 at 4-12 (C. Hans Rebuttal).

[215] Ex. 219 at 32 and Schedule (MAS-S-12) (M. St. Pierre Surrebuttal).

[216] Ex. 219 at 33 (M. St. Pierre Surrebuttal).

[217] Ex. 19 at 9 (S. DeMerritt Direct).

6) increased costs associated with a Mapping Project;

7) increased costs associated with Additional Positions at MERC;

8) increased costs associated with Depreciation and Return charges from IBS;

9) decreased costs associated with Memberships;

10) decreased costs associated with the General Allocation Factor;

11) decreased costs associated with Advertising Expense;

12) decreased costs associated with Long Term Incentive Pay, Restricted Stock, and Stock Option Expense;

13) decreased costs associated with Economic Development;

14) decreased costs associated with Incentives;

15) decreased costs associated with an audit of Vertex; and

16) decreased costs associated with Benefits.[218]

192. The OAG-AUD expressed concern with MERC's selection of a 2014 test year and recommended that $5,791,793, inclusive of inflation, be allowed for recovery rather than MERC's requested $6,615,783, which includes inflation and project costs that the OAG-AUD feels are not currently used and useful.

193. The OAG-AUD took the position that MERC's approach produces unreasonable costs for the test year. The OAG-AUD argued that MERC can add another year of inflation and adjustments by declaring that its test year is 2014 and project cost increases for both 2013 and 2014 based on its actual 2012 costs. The OAG-AUD recommended that the Commission reject MERC's 2014 test year designation and allow only a one-year inflation factor that encompasses both labor and general inflation based on MERC's historical O&M expenses.[219]

194. MERC disagreed with the OAG-AUD's approach to calculating O&M expense. If MERC had intended to use 2013 as the test year for purposes of setting rates, MERC would have filed for a 2013 test year at a time that interim rates would have been in effect for 2013. Instead, MERC prepared its filing based on a 2014 test year, and based the O&M for the 2014 test year on a 2012 historical test year because 2012 was the most recent historical year.[220]

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[218] Ex. 19 at 14-15 (S. DeMerritt Direct).

[219] Ex. 151 at 15, 21 (J. Lindell Direct); Ex. 154 at 6-7 (J. Lindell Surrebuttal).

[220] Ex. 24 at 21-22 (S. DeMerritt Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 24 (S. DeMerritt) (Doc ID No. 20145-99937-01).

195. The OAG-AUD also expressed concern with MERC's K&M factors. The OAG-AUD took the position that MERC identified what it claimed is a known event in 2013 and 2014, estimated its cost impact and labeled it a K&M change. The OAG-AUD concluded that while there may be known projects for 2013 and 2014; they were estimated by MERC and lack the precision that is usually attributable to a K&M change.[221]

196. MERC disagreed with the OAG-AUD's conclusion that MERC's approach to K&M is unusual. The approach used by MERC in the current docket is the same approach MERC used in its last two rate cases, Docket Nos. G007,011/GR-08-835 and G007,011/GR-10-977. Based on MERC's forecast for the 2014 test year, MERC identified known events (labor hires, mapping project, sewer lateral project, etc.) that will have a measurable impact on the 2014 test year.[222]

197. MERC's inflation adjustment is based on an average of inflation from Value Line, Global Insight, Moore Inflation Predictor, Energy Information Administration, and International Monetary Fund. MERC used 2.6 percent as a labor inflator rate based on union contract wage increases. MERC's calculated inflation between 2012 and 2014 is 3.74 percent on non-labor and 5.27 percent on labor.[223]

198. The OAG-AUD argued that MERC's use of consumer price index projections (i.e., external inflation projections) was not appropriate and recommended an internal inflation rate it developed based on MERC's historical O&M cost changes. The OAG-AUD concluded that MERC's inflation assumption suggests that the same number of employees will be employed at the same pay level in 2012 as will occur in the test year, there will be no effort to improve efficiencies and lower costs, and costs will continually rise.[224]

199. The OAG-AUD recommended that 2012 O&M expenses be inflated by 2.2 percent to determine the test year level of O&M expenses based on the three year average annual inflation shown in its calculations. The OAG-AUD concluded that MERC's methodology to inflate costs over two years was not reliable and had led to overinflated costs.[225]

200. The OAG-AUD's recommended adjustment is not appropriate. MERC filed this rate case assuming a 2014 test year and using a 2012 historical year as the basis for non-fuel O&M. Therefore, the OAG-AUD's recommendation to inflate 2012 data for one year to 2013 levels is without merit.[226]

201. The ALJ finds that MERC's test year non-fuel O&M expense and its K&M factors are appropriate. Because the record reflects that the OAG-AUD's recommended

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[221] Ex. 151 at 16-17 (J. Lindell Direct); Ex. 154 at 5-6 (J. Lindell Surrebuttal).

[222] Ex. 24 at 21-22 (S. DeMerritt Rebuttal).

[223] Ex. 19 at 9, 12-27 and Schedules (SSD-2 through SSD-19) (S. DeMerritt Direct); Ex. 24 at 19-25 (S. DeMerritt Rebuttal); Ex. 4 Initial Filing Volume 3: Informational Requirements, Document 5, Schedule C-6.

[224] Exs. 151 at 17-19 (J. Lindell Direct); Ex. 152 at Schedule (JJL-7) (Schedules to J. Lindell Direct).

[225] Ex. 151 at 19-20 (J. Lindell Direct).

[226] Ex. 24 at 23 (S. DeMerritt Rebuttal).

adjustment to MERC's initially filed test year non-fuel O&M expenses has already been made, and that an additional reduction to MERC's revised test year non-fuel O&M expenses would not accurately reflect MERC's test year costs, the ALJ finds that the OAG-AUD's recommended additional six percent reduction is not reasonable.

G. IBS-Customer Relations

202. The increase in billings from IBS-Customer Relations is made up of two components. The first component is related to MERC's contract with Vertex under which Vertex provides third-party customer service functions for MERC (call center, dispatch, billing, payment processing, etc.). The contract between MERC and Vertex for these services is for a multiple year term and contains annual cost escalators. MERC estimates that the K&M increase associated with these services will be $408,455 in 2014.[227]

203. The second component in the IBS Customer-Relations increase is related to the ICE 2016 project. The ICE 2016 project intends to unify the various billing systems currently in use across the Integrys platform and will result in a single billing system for all six Integrys regulated utilities.[228] The overall K&M associated with ICE in IBS-Customer Relations is $322,226 in 2014.[229]

204. The total IBS-Customer Relations K&M included in MERC's 2014 test year O&M expense is $730,681.[230]

205. The OAG-AUD recommended that the increase for IBS Customer Relations costs be denied. The OAG-AUD argued that MERC's customers should not be charged for services for both ICE and Vertex as MERC transitions to its new ICE and while Vertex costs are used and useful, ICE costs are not used and useful at this time.[231] The OAG-AUD recommended that MERC reduce O&M expense by $823,990 for IBS Customer Relations costs.[232]

206. MERC disagreed with the OAG-AUD's recommended adjustment. At a minimum the $408,455 cost increase associated with the Vertex contract is used and useful, as Vertex is currently providing the same billing and customer care services in 2014 as it has historically.[233]

207. The ICE 2016 project costs are used and useful in the provision of utility services and the Department has not raised a concern regarding these costs. Nonetheless, contingent on regulatory approval from the Commission, MERC would be willing to defer ICE costs totaling

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[227] Ex 19 at 15 (S. DeMerritt Direct).

[228] Ex. 10 at 3 (B. Kage Direct); Ex. 11 (M. Gerth Direct).

[229] Ex. 19 at 15 (S. DeMerritt Direct).

[230] Ex. 19 at 15 (S. DeMerritt Direct).

[231] Ex. 151 at 20-21 (J. Lindell Direct).

[232] Ex. 24 at 25 (S. DeMerritt Rebuttal).

[233] Ex. 24 at 25 (S. DeMerritt Rebuttal).

$322,226 annually as a regulatory asset until MERC's next rate case, with recovery of the regulatory asset from customers over a reasonable period (e.g., 3 years), to commence once the in-house customer service and billing systems has been implemented.[234]

208. The ALJ finds that MERC's total IBS-Customer Relations K&M of $730,681 is reasonable and should be accepted in this rate case.

H. IBS Vacancies

209. The K&M increase regarding the IBS vacancies creates a K&M of $240,583 in the 2013 projected test year and was appropriately inflated to 2014 levels. This adjustment relates to 72 positions that were either partially or fully vacated during the 2012 historical test year, and that IBS is forecasting to have filed in 2014.[235]

210. The ALJ finds that the K&M increase of $240,583 for IBS vacancies should be approved in this rate case.

I. Internal MERC Vacancies

211. The K&M increase for internal MERC vacancies creates a K&M of $392,647 in the 2013 projected test year and was appropriately inflated to 2014 levels. This adjustment relates to 6 positions that were either partially or fully vacated during the 2012 historical test year, and one position that was adjusted from a part time position to a full time position. MERC needs to fill these positions to maintain the level of service expected by its customers. MERC intends to have these positions filled by 2014.[236]

212. The ALJ finds that the K&M increase of $392,647 associated with internal MERC vacancies is appropriate and should be approved in this rate case.

J. Additional MERC Positions

213. The adjustment for eight additional MERC positions increased 2014 proposed O&M by $294,374.[237]

214. The ALJ finds that the O&M increase of $294,374 for additional MERC positions should be approved in this rate case.

K. Test Year Uncollectible Expenses

215. MERC forecasted $2,016,410 of uncollectible expense for the 2014 test year.[238]

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[234] Ex. 24 at 25 (S. DeMerritt Rebuttal).

[235] Ex. 19 at 21 and Schedule (SSD-10) (S. DeMerritt Direct).

[236] Ex. 19 at 16 (S. DeMerritt Direct).

[237] Ex. 19 at 19-20 and Schedule (SSD-8) (S. DeMerritt Direct).

[238] Ex 24 at 9-10 and Schedule (SSD-3) (S. DeMerritt Rebuttal).

216. The Department expressed concern with MERC's proposed test year uncollectible expense ratio and recommended that MERC use the 2013 uncollectible expense ratio for purposes of uncollectible expense. In addition, the Department recommended that the Commission decrease MERC's uncollectible expense to $1,431,381 (i.e., by $334,503).[239]

217. MERC disagreed with the Department's recommendation to use the 2013 uncollectible expense ratio for purposes of uncollectible expense. The three-year uncollectible expense ratio proposed by MERC is consistent with what the Commission approved in MERC's 2008 and 2010 rate cases. In fact, the Department justified the levelization approach when forecasting uncollectible expense in its Direct Testimony in MERC's last rate case, Docket No. G007,011/GR-10-977. The OAG-AUD also supported the levelization approach in its Surrebuttal Testimony in the same docket. Therefore, based on past Commission precedent, as well as past support from the Department and the OAG-AUD, MERC believes the levelization approach is a more reasonable method than picking a fixed point in time.[240]

218. The OAG-AUD recommended including uncollectible expense of $1,350,000 in the test year. According to the OAG-AUD, using a historical average of uncollectible expense as MERC proposed can produce inaccurate estimates. The OAG-AUD concluded that MERC's historical analysis shows fairly significant fluctuations from year to year and does not provide a reasonable estimate of uncollectible expense for the test year.[241] The OAG-AUD maintained its opposition to MERC's levelization approach, stating that, unlike the Department, MERC had failed to include the most recently completed year (2013) in its levelization calculations.[242]

219. MERC disagreed with the OAG-AUD's recommended adjustment. It was well documented in MERC's last rate case that uncollectible expense fluctuates from year to year. The OAG-AUD recognizes this fluctuation in its Direct Testimony in this case. In addition, the three year uncollectible expense ratio proposed by MERC is consistent with the approach taken by the Commission in MERC's past rate case filings. Therefore, MERC maintains that using an average ratio of uncollectible expense over revenues is the correct approach for calculating uncollectible expense.[243]

220. MERC proposed to update the uncollectible expense calculation and include $12,000,000 for an assumed rate increase based on MERC's current position for the revenue requirement.[244] The Department disagreed with MERC's proposal and stated that it will

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[239] Ex. 217 at 39-40 (M. St. Pierre Direct); Ex. 218 at Schedule (MAS-25) (Attachments to M. St. Pierre Direct); Ex. 219 at 35-36 (M. St. Pierre Surrebuttal).

[240] Ex. 24 at 9 (S. DeMerritt Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 23 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

[241] Ex. 151 at 6-7 (J. Lindell Direct).

[242] Ex. 154 at 3-4 (J. Lindell Surrebuttal).

[243] Ex. 24 at 20-21 (S. DeMerritt Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 24 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

[244] Ex. 24 at 9-10 and Schedule (SSD-3) (S. DeMerritt Rebuttal); Ex. 42 at Schedule (GJW-1) (G. Walters Rebuttal)

continue to calculate uncollectible expense based on the Department's position for revenue and the deficiency.[245]

221. The ALJ finds that MERC's three-year uncollectible expense ratio and forecasted $2,016,410 of uncollectible expense for the 2014 test year is reasonable and should be accepted in this rate case.

L. Sewer Lateral Expense

222. MERC's adjustment for sewer lateral expense increases 2014 proposed O&M by $340,000. The Sewer Lateral Pilot program is being done to comply with requests from the Minnesota Office of Pipeline Safety ("MNOPS"). The goal is to validate that MERC does not have conflicts with sewer lines that could present risk to its customers.[246] Details regarding the Sewer Laterals Pilot Program (e.g., start time, duration, employees, cost, etc.) are included in MERC's response to the Department's Information Request Document number 147.[247]

223. The Department initially concluded that the Sewer Laterals Pilot Program is a one-time project since the project was projected to be done by the end of the test year and affected only the community of Cannon Falls. The Department recommended that the Sewer Laterals Pilot Program costs be levelized over three years and recommended a reduction of $226,667 to rate base.[248]

224. MERC disagreed with the Department's proposed adjustment and pointed out that the Sewer Lateral Pilot Program is a multi-year project that will extend beyond 2014 and the community of Cannon Falls. Therefore, MERC maintained its position that inclusion of the $340,000 of Sewer Lateral Pilot Program costs in the 2014 test year is appropriate.[249]

225. In Surrebuttal Testimony, the Department determined that the Sewer Laterals Pilot Program is a multi-year project that extends beyond the community of Cannon Falls. As a result, the Department recommended that the Commission accept MERC's proposed test year Sewer Laterals Pilot Program costs.[250]

226. The ALJ finds that MERC's inclusion of $340,000 of Sewer Lateral Pilot Program costs in the 2014 test year is appropriate.

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[245] Ex. 219 at 37-38 and Schedule (MAS-S-10) (M. St. Pierre Surrebuttal).

[246] Ex. 19 at 17 and Schedule (SSD-5) (S. DeMerritt Direct).

[247] Evidentiary Hearing Transcript (May 13, 2014) at 44 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

[248] Ex. 217 at 40-43 (M. St. Pierre Direct); Ex. 218 at Schedules (MAS-26, MAS-27) (Attachments to M. St. Pierre Direct).

[249] Ex. 24 at 10 (S. DeMerritt Rebuttal).

[250] Ex. 219 at 39 (M. St. Pierre Surrebuttal).

M. Gate Station Expense

227. The adjustment for the gate stations increases 2014 proposed O&M by $330,000. The Gate Station Project will add remote monitoring and some test measurement to the distribution delivery points where MERC receives its natural gas supply from the pipelines. Today, MERC does not have remote monitoring ("visibility") on the pressure, temperature or volumes on a real time basis. Remote monitoring will give MERC engineering and gas control more real time visibility to the performance of the Company's systems.[251] Details regarding the mapping project (e.g., start time, duration, employees, cost, etc.) are included in MERC's response to the Department's Information Request Document number 148.[252]

228. The Department concluded that the Gate Stations project is a long-term, rather than one-time project. The Department concluded that MERC's proposed recovery of costs related to the Gate Stations project was reasonable.[253]

229. Constellation requested that MERC complete the Gate Station project prior to October 1, 2014.[254]

230. The gate station project is a multi-year project that will not be completed in 2014.[255]

231. The ALJ finds that MERC's proposed recovery of costs related to the Gate Stations project is reasonable and should be approved in this rate case.

N. Mapping Project

232. The adjustment for the Mapping Project increases 2014 proposed O&M by $330,000. MERC has identified gaps with its mapping accuracy that field personnel utilize to locate lines, manage outages, determine flow modeling, and other critical infrastructure tasks. These errors have come from a number of map conversions as companies were acquired, sold, and consolidated. To improve the quality and utilization of the mapping systems, MERC plans to validate the accuracy by verifying as built drawings and actual field data. Today MERC does not have the ability to verify age of pipe, materials, fittings, etc. This information is needed to complete required Department of Transportation reporting which is not available for MERC today due to the incomplete or inaccurate information.[256] Details regarding the Mapping Project (e.g., start time, duration, employees, cost, etc.) are included in MERC's response to the Department's Information Request Document number 149.[257]

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[251] Ex. 19 at 17-18 and Schedule (SSD-6) (S. DeMerritt Direct).

[252] Evidentiary Hearing Transcript (May 13, 2014) at 45 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

[253] Ex. 217 at 48-49 (M. St. Pierre Direct); Ex. 219 at 41-42 (M. St. Pierre Surrebuttal).

[254] Ex. 125 at 4 (R. Haubensak Direct).

[255] Ex. 24 at 28 (S. DeMerritt Rebuttal).

[256] Ex. 19 at 18-19 and Schedule (SSD-7) (S. DeMerritt Direct).

[257] Evidentiary Hearing Transcript (May 13, 2014) at 44 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

233. The Department concluded that the Mapping Project was a one-time project since it was projected to be done by the end of the test year. The Department recommended that the Mapping Project costs be levelized over three years and recommended a reduction of $220,000 to rate base.[258]

234. MERC disagreed with the Department's proposed adjustment. Although the Mapping Project is a project that will only incur costs in 2014, when considering how the Department's proposed adjustment will impact MERC in future years, the Department proposes a single rate making adjustment for 2015 and 2016 (reducing revenues), with no consideration for any future increases in MERC's overall costs. MERC did not file a 2015 test year rate increase, and does not intend to. Any increases and decreases in expenses that occur in 2015 as compared to test year 2014 will need to be managed by MERC management. MERC believes making an adjustment for a single item, with no consideration for the future costs, sales, or capital requirements of other items, is punitive and the Company does not agree with the adjustment. MERC has stated its intention to file a 2016 rate case so, at a minimum, this adjustment should only be spread over two years at $165,000 per year versus the $113,333 per year advocated by the Department. However, MERC does not agree with the Department's position and maintains the $330,000 Mapping Project cost originally proposed by MERC is appropriate and proper for calculating MERC's test year 2014 revenue deficiency.[259]

235. The ALJ finds that MERC's $330,000 of Mapping Project cost is appropriate and proper for calculating MERC's test year 2014 revenue deficiency in this rate case.

O. Organization Membership Dues

236. MERC has excluded all organization membership dues from the 2014 proposed test year. This adjustment reduces 2013 projected O&M expense by $1,546. By removing this amount in 2013, these costs are also effectively removed from the 2014 proposed test year.[260]

P. Deprecation and Return Cross Charges from IBS

237. The K&M adjustment for depreciation and return on cross charges from IBS relates to two specific projects at IBS that are then cross charged to the various subsidiaries. These two projects are GMS Software and ICE. This adjustment increases 2013 projected O&M expense by $187,615, and 2014 O&M expense after inflation by $92,855. The total O&M expense charged to MERC for these two projects in the 2014 proposed test year is $280,470.[261]

238. The OAG-AUD argued that although the IBS charges are purportedly for increases in depreciation and a return on assets, MERC did not identify the scope of the project costs, nor how these projects would be applicable to MERC's operations to justify an allocation

[258] Ex. 217 at 46 (M. St. Pierre Direct); Ex. 218 at Schedules (MAS-28, MAS-29) (Attachments to M. St. Pierre Direct); Ex. 219 at 40-41 (M. St. Pierre Surrebuttal).

[259] Ex. 24 at 10-11 (S. DeMerritt Rebuttal).

[260] Ex. 19 at 22 and Schedule (SSD-11) (S. DeMerritt Direct).

[261] Ex. 19 at 20 and Schedule (SSD-9) (S. DeMerritt Direct).

to MERC along with MERC's other affiliates. The OAG-AUD takes the position that while there may be known projects for 2013 and 2014, they were estimated by MERC and lack the precision that is usually attributable to a K&M change.[262]

239. The Company's K&M adjustment related to depreciation and return on assets cross charged from IBS is precise. As previously discussed, the increase is due to two projects: GMS Software and ICE.[263]

240. The ALJ finds that MERC's K&M adjustment related to depreciation and return on assets cross charged from IBS of $280,470 should be approved for 2014.

Q. Economic Development Expenses

241. To be consistent with the costs allowed in Docket No. G007,011/GR-10-977, MERC has removed 50 percent of the 2012 Economic Development costs in the 2013 projected test year. By removing this amount in 2013, these costs are also effectively removed from the 2014 proposed test year.[264]

R. Advertising Expense

242. MERC included a known and measurable adjustment to test year O&M expense for advertising costs.[265]

243. MERC has excluded all advertising costs associated with economic development and goodwill from the 2014 proposed test year. This adjustment reduces 2013 projected O&M expense by $5,308. By removing this amount in 2013, these costs are also effectively removed from the 2014 proposed test year.[266]

244. MERC's filing includes a list of the advertisements for which MERC seeks cost recovery in this case, and an explanation of each advertisement.[267]

245. MERC's advertising costs are appropriate and should be accepted in this rate case.

S. General Cost Allocator

246. Since MERC's acquisition by Integrys, IBS has employed a two factor formula for the General Cost Allocator ("GCA"). In past rate cases, MERC has requested authority to use the two factor formula as opposed to the currently authorized one factor formula. This

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262 Ex. 151 at 16-17 (J. Lindell Direct).

263 Ex. 24 at 22-23 (S. DeMerritt Rebuttal).

264 Ex. 19 at 23-24 and Schedule (SSD-15) (S. DeMerritt Direct).

265 Ex. 19 at 22-23 and Schedule (SSD-13) (S. DeMerritt Direct).

266 Ex. 19 at 22-23 at Schedule (SSD-13) (S. DeMerritt Direct).

267 Ex. 19 at 23 (S. DeMerritt Direct).

request has previously been denied. Therefore, in this current docket, MERC is decreasing the O&M expense by $3,371 in the 2013 projected test year to account for the difference between the one factor and two factor allocation methodologies. By removing this amount in 2013, these costs are also effectively removed from the 2014 proposed test year.[268]

T. Vertex Audit

247. In Docket No. G007,011/GR-10-977 MERC was ordered to perform an audit via a third party of its Vertex billing system, and was not permitted to collect these costs from rate payers. In 2012, MERC had invoices from the third party auditor of $303,521, and removed these costs plus inflation from the 2013 projected test year. By removing this amount in 2013 these costs were effectively removed from the 2014 test year.[269]

U. Long Term Incentive Compensation

248. In Docket No. G007,011/GR-10-977, costs associated with Long Term Incentive Plan ("LTIP"), Restricted Stock and Stock Options were disallowed. Therefore, MERC is decreasing O&M expenses by $402,878 in the 2013 projected test year. By removing this amount in 2013, these costs are also effectively removed from the 2014 proposed test year.[270]

V. Employee Incentive Compensation

249. MERC requested recovery of 100 percent of its non-executive incentive plan compensation and 30 percent of its executive incentive plan compensation.[271]

250. Integrys maintains a non-executive incentive plan. Non-union, non-executive employees of MERC participate in the non-executive incentive plan. Employees of IBS also participate in the non-executive incentive plan as the IBS goals include the System Reliability, Employee Safety, and Customer Satisfaction metrics of MERC, weighed based on the proportion that IBS costs are generally allocated to MERC.[272]

251. MERC maintains compensation programs that are market-based so that it can attract and retain a qualified and motivated work force. MERC's cash compensation goal is to pay its employees a total cash compensation package (base pay plus target incentive pay) that is anchored to market median levels as compared to other energy industry companies. MERC defines the market median as the 50th percentile median of comparable energy industry and general industry companies.[273]

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[268] Ex. 19 at 22 and Schedule (SSD-12) (S. DeMerritt Direct).

[269] Ex. 19 at 24 (S. DeMerritt Direct).

[270] Ex. 19 at 23 and Schedule (SSD-14) (S. DeMerritt Direct).

[271] Ex. 13 at 11-12 (N. Cleary Direct).

[272] Ex. 13 at 3 and Schedule (NEC-1) (N. Cleary Direct).

[273] Ex. 13 at 3-4 (N. Cleary Direct).

252. There are two reasons MERC needs to use an incentive compensation package rather than pay employees exclusively through base pay. First, incentive pay is necessary in order to allow MERC to compete with other companies for quality employees because surveys have shown that a majority of companies provide incentive programs. Second, MERC's incentive plans are necessary to incentivize employees to improve service levels and reduce costs that impact the rates paid by customers.[274]

253. MERC's non-executive incentive compensation package directly benefits customers: it ensures there are highly proficient employees to perform customer work; maintaining and improving the productivity of and quality of work performed reduces overall costs to rate payers and improves customer satisfaction; MERC is able to avoid incurring the additional costs of hiring and training employees to replace workers; and employees that are familiar with MERC's systems and equipment tend to be more efficient in their performance.[275]

254. The Commission approved the inclusion of MERC's non-executive compensation package in the Company's 2010 rate case, where it granted MERC 100 percent recovery of non-executive compensation and 30 percent recovery of executive compensation.[276]

255. MERC's non-executive incentive plan measures assess cost control via a non-fuel O&M expense-adjusted metric which is weighted at 50 percent of the total. Customer service, system reliability, and employee safety measurements are weighted at a combined 50 percent of the total.[277]

256. Integrys' earnings per share is 70 percent of the Executive Incentive Plan goals, and 30 percent of the goals are based on customer satisfaction, employee safety, and environmental impact. Consistent with MERC's practice in Docket No. G-007,011/GR-10-977, MERC proposed to recover the 30 percent of executive incentive compensation in rates.[278]

257. The Department recommended a $27,857 reduction to general expense for MERC's executive incentive compensation costs. The Department also recommended that MERC retain the existing incentive compensation refund mechanism.[279]

258. MERC agreed with the Department's recommendation to reduce administrative and general expense by $27,857 for executive incentive compensation.[280] MERC also agreed with the Department's recommendation that the Company retain the existing incentive compensation refund mechanism, but requested that the refund be calculated beginning with test

[274] Ex. 13 at 4-5 (N. Cleary Direct).

[275] Ex. 13 at 5 (N. Cleary Direct).

[276] Ex. 13 at 4 (N. Cleary Direct).

[277] Ex. 13 at 6-11 (N. Cleary Direct).

[278] Ex. 13 at 12 (N. Cleary Direct).

[279] Ex. 217 at 37 (M. St. Pierre Direct).

[280] Ex. 24 at 8 (S. DeMerritt Rebuttal).

year 2014, based on the incentive compensation and customer counts approved in this rate case docket.[281]

259. The K&M decrease associated with incentive costs is $286,221. The 2014 incentive costs for non-executive employees was calculated at the target level expense, and the executive employee incentives were included at 30 percent to be consistent with the costs approved in Docket No. G007,011/GR-10-977.[282]

MERC's proposed test year non-executive and executive incentive compensation plans have reasonable performance goals, directly benefit customers, and should be included in the test year revenue requirement.

W. Aquila Transaction Costs

260. MERC has not included any acquisition or transaction costs associated with the sale of Aquila's Minnesota assets to MERC. MERC is basing its 2014 O&M forecast on 2012 actual plus K&M's. There were not any acquisition or transaction costs associated with the sale of Aquila's Minnesota assets to MERC in the 2012 historical year; therefore, there are no costs to inflate into the 2014 proposed test year.[283]

X. Gas Storage Balance Adjustment

261. MERC's original cost of gas and gas in storage balances were updated using NYMEX data from May 15, 2013, as described in the Base Cost of Gas filing in Docket No. G011/MR-13-732.[284] MERC's cost of gas and gas in storage balances were updated on April 15, 2014, using NYMEX data from March 17, 2014, as described in the Base Cost of Gas filing in Docket Nos. G011/GR-13-617 and G011/MR-13-732. The increase in rate base for the updated Base Cost of Gas filing increased MERC's initially filed gas storage balance from $12,013,242 to $12,866,941.[285]

262. Based on the updated Base Cost of Gas filing in Docket Nos. G011/MR-13-372 and G011/GR-13-617, MERC recommended that its gas storage balance be set at the 13-month average balance of $12,866,941, which was $853,699 higher than the balance after the March 17, 2014 base cost of gas update.[286]

263. The Department agreed with MERC's recommendation.[287]

264. The ALJ finds that MERC's gas storage balance should be $12,866,941 for 2014.

[281] Ex. 24 at 14 (S. DeMerritt Rebuttal).

[282] Ex. 19 at 24 (S. DeMerritt Direct).

[283] Ex. 19 at 25 (S. DeMerritt Direct).

[284] Ex. 19 at 8 (S. DeMerritt Direct).

[285] Ex. 24 at 29 (S. DeMerritt Rebuttal).

[286] Ex. 24 at 26 and Schedule (SSD-4) (S. DeMerritt Rebuttal); Ex. 216 at 8 (L. La Plante Surrebuttal).

[287] Ex. 216 at 8 (L. La Plante Surrebuttal).

Y. Net Operating Loss Deferred Tax Asset

265. MERC included a deferred tax asset ("DTA") for a net operating loss ("NOL") carryforward in rate base. The DTA represents MERC's stand-alone operating income NOL that arose in 2012 and 2013 due primarily to bonus depreciation. MERC has experienced several consecutive years of NOLs, primarily due to bonus tax depreciation deductions. Until this rate case, MERC was not in the position of having to reflect the related allowance for deferred income taxes related to a carryforward of a NOL balance from any prior year. The consecutive years of a NOL have primarily been due to the continual extension of the federal economic incentive allowing for additional bonus depreciation deductions over that period.

266. A federal NOL can be carried back two years, and forward 20 years. If a utility has more tax deductions than taxable income in a given tax year, it has a tax NOL. Because MERC and Integrys have incurred NOLs during 2012 and 2013 greater than the taxable income generated in 2010 and 2011 (the two year carryback period), MERC is in the position of carrying forward the NOL.[288]

267. If MERC does not include a DTA in its rate base, the Company will be in violation of the tax normalization rules. The normalization rules related to a federal NOL can be summarized as a requirement that the utility has to have realized the tax cash flow benefit of claiming accelerated depreciation before the deferred tax liability that results from claiming accelerated depreciation is included in rate base. Therefore, the tax normalization rules require MERC to carry a DTA for the NOL balance from 2012 and 2013 that resulted from claiming accelerated tax depreciation, until used during 2014. An example of a NOL situation similar to MERC's can be found in IRS Private Letter Ruling ("PLR") 8818040.[289]

268. A violation of the normalization rules would create severe detriment for both MERC and its customers. The normalization rules are long-standing and Congress has been unwavering in its mandate. These rules have been in force and the impact of noncompliance known to utilities and regulators for the past four decades. Compliance is not optional and the rules can be violated directly or indirectly. Thus, it is important not to take steps that would have the unintended consequence of MERC losing the ability to continue to claim the rate base reducing impacts of accelerated and bonus depreciation.[290]

269. The OAG-AUD rejected MERC's proposed adjustment for its DTA NOL carryforward. The OAG-AUD took the position that MERC's proposed adjustment is very rarely utilized to set rates and MERC's tax position does not support the proposed adjustment. The OAG-AUD further argued that MERC is not the taxpayer that can claim a NOL. According to the OAG-AUD, MERC did not demonstrate that it has contributed to the NOL carryforward of Integrys, nor has it shown whether, and to what extent, the tax NOLs are due to affiliates that are public utilities and to affiliates that are not public utilities. Thus, according to the OAG-AUD, MERC has not demonstrated that the normalization rules would be violated absent the

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288 Ex. 36 at 3-4 (J. Wilde Direct).

289 Ex. 36 at 5-6 (J. Wilde Direct).

290 Ex. 36 at 6-7 (J. Wilde Direct).

adjustment for deferred taxes that the Company proposes. The OAG-AUD also took issue with the PLR relied upon by MERC to support MERC's DTA NOL adjustment. The OAG-AUD argued that the PLR is inapplicable to MERC because: 1) MERC is a member of a consolidated group for tax purposes whereas the taxpayer in the PLR was not; and 2) a normalization violation can only be attributed to a public utility and the utility's tax loss must be attributable to accelerated depreciation or other tax timing differences between book and tax reporting. The OAG-AUD stated that a PLR cannot be used or cited as precedent. The OAG-AUD asserted that the tax NOL carryforward will be utilized in 2014.[291]

270. While it is uncommon for a regulated public utility that is a member of a federal consolidated group to have a DTA NOL carryforward, it does not support exclusion of the DTA when it does occur. The tax normalization rules apply to NOLs for public utilities and, as indicated in the OAG-AUD's testimony, the NOL DTA was included in at least one public utility's rate base. Each subsidiary of Integrys, including MERC is considered a taxpayer that has the ability to generate a tax liability, as well as avail itself of other tax attributes such as a net operating loss carryforward. The tax normalization rules have consistently been applied by the IRS at the individual regulated public utility level. MERC only considered the taxable income and NOL carryforward position of Integrys Consolidated Group to determine in what year MERC's regulated public utility operations would fully benefit from the accelerated tax deductions MERC claimed during 2012 and 2013. MERC will not fully realize and benefit from the NOL DTA until sometime during 2014. Although the PLR cannot be cited as precedent, taxpayers do refer the IRS to previously issued PLRs when applicable and the IRS does consider prior PLRs when reaching conclusions with respect to similarly-situated taxpayers.[292]

271. The ALJ finds that MERC's DTA NOL carryforward should be approved.

Z. Additional Property Tax Expense

272. MERC filed this general rate proceeding with an estimated property tax expense of $7,314,733 (inclusive of $375,000 of property tax on storage gas and 5.08 percent inflation), or $712,679 more than the amount included in the 2012 historic test year.[293]

273. The Department recommended a reduction of $48,260 to MERC's property tax expense, reducing the amount from $7,314,129 to $7,265,869.[294]

274. MERC agreed with the Department's recommendation. In addition, MERC proposed an additional property tax decrease of $70,000 in its property taxes for the Company's Kansas property taxes on storage gas, from $375,000 to $305,000. This reduction reflected the revised tax assessment estimates from 2009 through 2013 that MERC received from the Kansas

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[291] Ex. 151 at 7-11 (J. Lindell Direct); Ex. 154 at 9-12 (J. Lindell Surrebuttal).

[292] Ex. 37 at 11-21 (J. Wilde Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 96 (J. Wilde) (Doc. ID No. 20145-99937-01).

[293] Ex. 36 at 11 and Schedule (JRW-1) (J. Wilde Direct).

[294] Ex. 217 at 25 and Schedule (MAS-19) (M. St. Pierre Direct); Ex. 219 at 21 (M. St. Pierre Surrebuttal).

Attorney General.[295] MERC recommended a total reduction of its as filed estimate of $118,864, from $7,314,733 to $7,195,869.[296]

275. The Department agreed with MERC's additional adjustment of $70,000 to property tax expense for a total reduction of $118,260 related to property tax expense.[297] MERC agreed to this adjustment during the evidentiary hearing.[298]

276. The OAG-AUD proposed a reduction of $690,700 to MERC's property tax expense, reducing the amount from $7,314,733 to $6,624,033.[299] The OAG-AUD claimed that MERC attempted to over-inflate its costs by using a future test year – 2014 – based on the Company's base year 2012 actual costs. According to the OAG-AUD this produces an unreasonable increase in costs, including property taxes and the OAG-AUD recommends that property taxes for 2013 be used as test year property taxes. The OAG-AUD bases its recommendation on a review of sample property tax statements from Washington County for a single MERC property located in Scandia, Minnesota.[300]

277. MERC disagreed with the OAG-AUD's recommendation. MERC's actual tax liability for 2012, which was paid in 2013, was greater than the estimate the OAG-AUD relied on to calculate MERC's 2014 property tax expense. MERC provided support, using actual data, for the Company's expectation that its 2013 property tax should increase on a statewide basis, and provided a reasonable method to estimate property tax obligations for 2014 using actual valuation methods and assumptions utilized by the State of Minnesota when developing valuations of MERC's property for 2013.[301]

278. The Department recommended that the Commission require MERC to make a compliance filing upon resolution of the Kansas property tax appeal, and refund with interest all Kansas property taxes not paid to the Kansas Revenue taxing authorities but collected from ratepayers.[302]

279. MERC agreed with the Department's recommendations.[303]

280. MERC has formally appealed the Company's Minnesota property tax assessments for years 2008 through 2013. None of the years appealed were resolved through the

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[295] Ex. 37 at 4 and Schedule (JRW-1) (J. Wilde Rebuttal).

[296] Ex. 37 at 5-6 (J. Wilde Rebuttal).

[297] Ex. 219 at 21 (M. St. Pierre Surrebuttal).

[298] Evidentiary Hearing Transcript (May 13, 2014) at 94-103 (J. Wilde) (Doc. ID No. 20145-99937-01).

[299] Ex. 151 at 13 (J. Lindell Direct).

[300] Ex. 151 at 12-13 (J. Lindell Direct).

[301] Ex. 37 at 7-9 (J. Wilde Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 94-103 (J. Wilde) (Doc. ID No. 20145-99937-01).

[302] Ex. 217 at 23 (M. St. Pierre Direct).

[303] Ex. 37 at 4-5 (J. Wilde Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 94-103 (J. Wilde) (Doc. ID No. 20145-99937-01).

administrative process and MERC is now pursuing resolution through the Minnesota Tax Court. The appeals were heard in Minnesota Tax Court from February 10, 2014 through February 19, 2014. Closing arguments were set for June 18, 2014 and MERC anticipates that the Minnesota Tax Court will issue its decision sometime this fall. MERC is unable to predict the outcome of these appeals. Pending a resolution of the appeals, MERC is obligated to pay its property tax obligations based on the increased property value assessments.[304]

281. MERC has formally appealed a recent ruling of the Kansas Supreme Court that the storage gas of public utilities like MERC that is allocable to Kansas is subject to property taxation in Kansas. MERC has joined other public utilities with storage gas volumes allocated to Kansas to seek a review of the Kansas Supreme Court's decision by the U.S. Supreme Court. The decision by the U.S. Supreme Court whether to conduct a review of the Kansas Supreme Court ruling is expected towards the end of 2014. MERC is unable to predict the outcome of this appeal.[305]

282. The Department requested additional updates regarding the appeals, which MERC agreed to provide at the evidentiary hearing in May 2014. Pursuant to the Department's recommendations, MERC also agreed to notify the Commission of any court rulings issued prior to the Commission's Final Order in this proceeding.[306]

283. At the evidentiary hearing, MERC provided an update with respect to the Minnesota and Kansas property tax appeals. With respect to the Minnesota tax appeal, closing arguments are scheduled for the middle of June and a ruling is expected by the Court within 90 days of the closing arguments. The Minnesota Department of Revenue, in its post-trial brief to the Minnesota Tax court is actually seeking an increase in MERC's property tax assessment for 2008 through 2012. With respect to the Kansas appeal, the U.S. Supreme Court is expected to rule with respect to whether it will hear MERC's (and others') Kansas property tax appeal in late summer or early fall of this year.[307]

284. The ALJ finds that MERC's recommended property tax reduction of $118,260 is appropriate in this rate case.

285. The ALJ finds that the Commission should take administrative notice of any decisions on MERC's property tax appeals made before the final order in this proceeding.

AA. IBS Cost Allocation Adjustment

286. MERC proposed to use a two-factor formula to account for how IBS allocates costs to MERC and its other regulated affiliates. Using this method, IBS uses an average of two percentages for each entity to calculate its General/Corporate Allocation Factor: 1) total assets

[304] Ex. 36 at 10 (J. Wilde Direct); Ex. 37 at 3 (J. Wilde Rebuttal).

[305] Ex. 37 at 3 (J. Wilde Rebuttal).

[306] Ex. 37 at 3 (J. Wilde Rebuttal); Ex. 217 at 24 (M. St. Pierre Direct).

[307] Evidentiary Hearing Transcript (May 13, 2014) at 97 (J. Wilde) (Doc. ID No. 20145-99937-01).

(with some exclusions for derivative assets, goodwill and other "non-ordinary" assets); and 2) total non-fuel O&M costs.[308]

287. MERC seeks to recover the costs allocated to the Company under the Regulated AIA in this rate case. The MERC 2014 gas revenue requirement includes actual amounts charged in 2012, inflated to 2014, and adjusted for K&M changes for the services that IBS provides to MERC. MERC does not seek to recover the difference in costs calculated using the General/Corporate Allocation method in the Regulated AIA and the Commission's preferred general allocation method. The two methods produced similar results with a difference between the two methods of $3,314 in 2012. MERC is seeking to recover the smaller amount provided by the Commission's preferred allocation method.[309]

288. The Department testified that the Commission's preferred general allocation method is computed by using the ratio of all expenses directly assigned or attributed to regulated and non-regulated activities, excluding the cost of fuel, natural gas, purchased power, and the purchased cost of goods sold.[310] Because MERC is seeking to recover the smaller amount provided by the Commission's preferred general allocation method in this rate case, the Department concluded that MERC's approach is reasonable.[311]

289. The ALJ finds that MERC's IBS Cost Allocation adjustment is consistent with the Commission's preferred general allocation method and should be approved in this rate case.

BB. MERC's Cost Allocations to ServiceChoice

290. In Direct Testimony, MERC explained that it uses three different means of allocating the costs to the utility and non-utility businesses: direct charge, allocation based on known factors, and general allocation.[312]

291. The Department recommended that the Commission accept the results of MERC's cost allocations to ServiceChoice in this rate case.[313]

292. The ALJ finds that MERC's Cost Allocations to ServiceChoice are reasonable and should be accepted in this rate case.

CC. Rate Case Expense

293. MERC forecasted total rate case expenses of $1,715,000 and proposes to amortize 87.7 percent, or $1,504,055, over a two-year period. The 87.7 percent reflects the removal of rate case expenses for MERC's non-utility business "ServiceChoice." This amortization resulted

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308 Ex. 12 at 15-18 (T. Kupsh Direct).

309 Ex. 12 at 2-3, 10-21 and Schedule (TLK-3) (T. Kupsh Direct).

310 Ex. 215 at 5-6 (L. La Plante Direct).

311 Ex. 215 at 9 (L. La Plante Direct).

312 Ex. 40 at 35 (G. Walters Direct).

313 Ex. 215 at 12 (L. La Plante Direct).

in test year expenses of $752,028. The types of expenses included are costs for MERC's capital expert, legal fees, charges from Vertex for changes to the billing system, state agency and Administrative Law Judge fees, newspaper notices, and travel expenses.[314]

294. In Docket No. G007,011/GR-10-977, MERC was ordered to track rate case expense recoveries exceeding the authorized test year expense for possible crediting against the revenue requirement in the next rate case. MERC's current proposed rate case proposes new rates, either final or interim, to take effect January 1, 2014, inclusive of MERC's rate case expenses in this current docket. Therefore, no recovery for rate case expenses authorized in Docket No. G007,011/GR-10-977 is included in this rate case.[315]

295. The Department recommended that $21,925 of MERC's estimated travel expenses be removed from the proposed test year rate case expenses. Based on a review of MERC's rate case expenses, the Department determined that MERC has no actual travel expense related to rate expenses in the last case, Docket No. G007,011/GR-10-977; however the Company estimated an amount of $25,000 of travel expenses to be included in the rate case expense in this proceeding. Further review showed that MERC had included $10,500 of travel expenses in its 2010 rate case expenses. Thus, it appeared to the Department that there could be double recovery since the Company also has a Travel and Entertainment ("T&E") expenses account included for recovery in this proceeding. The Department's recommended removal of $21,925 from rate case expense is the result of allocating 87.7 percent of $25,000 to MERC.[316]

296. MERC agreed with this adjustment.[317]

297. The Department recommended a three-year amortization period for rate case expenses. The Department explained that because the amount of time between rate cases typically varies from the time estimated by utilities in their rate cases, the Department generally calculates an average time period over which to recover rate case expenses. The Department applied this averaging calculation to MERC's previous general rate case filings and recommended that MERC be allowed to recover its rate case expenses over a period of three years. The Department noted that this is the same recovery period approved by the Commission in MERC's 2008 and 2010 rate cases. Based on its recommended three-year recovery period, the Department recommended that test year rate case expenses be reduced by a net amount of $257,984.[318]

298. MERC disagreed with the Department's recommendation and calculation of the amortization period. MERC concluded that the Department's recommendation inappropriately used simple averaging and was based on a very narrow history of MERC rate cases. MERC also concluded that the Department's acknowledgement that estimating a reasonable amortization period is difficult because many things can impact a utility's decision to file a rate case undercut

[314] Ex. 19 at 9, 27 and Schedule (SSD-20) (S. DeMerritt Direct).

[315] Ex. 19 at 28 (S. DeMerritt Direct).

[316] Ex. 215 at 13-14 (L. La Plante Direct).

[317] Ex. 24 at 15 (S. DeMerritt Rebuttal).

[318] Ex. 215 at 15-16 (L. La Plante Direct); Ex. 216 at 9-10 (L. La Plante Surrebuttal).

the Department's simple average analysis.[319] MERC provided support in its testimony for the possibility that the Company may file a rate case in 2015 using a 2016 test year.[320]

299. A two-year amortization period is appropriate because MERC is currently preparing for an increase in capital expenditures. In addition, MERC has announced the proposed acquisition of Interstate Power and Light's ("IPL") natural gas distribution assets which is subject to Commission approval. If approved, it is anticipated that the revenues, cost, rate base, as well as rate consolidation with the IPL customers will also be addressed in the next rate case.[321]

300. MERC proposed that if the Commission agrees with the Department's recommendation for a three-year amortization period, MERC recommends debiting the unamortized rate case balance of $257,985 on an annualized basis, and crediting amortization expense for the same amount.[322]

301. The Department recommended the removal of unamortized rate case expenses in the amount of $1,315,335 from rate base. According to the Department, rate case costs are not prepaid costs and should not be included in rate base.[323] The OAG-AUD agreed with the Department's recommendation.[324]

302. MERC agreed with the removal of unamortized rate case expenses from rate base, but noted that if the unamortized rate case expenses are removed then the associated deferred taxes of $541,188 also need to be removed from rate base.[325]

303. The Department agreed with MERC's additional adjustment of $541,188, but reduced it slightly to reflect the allocated amount for the Minnesota Jurisdiction. Specifically, the Department recommended that rate base exclude unamortized rate case expenses of $1,312,704 and its related deferred taxes of $540,106. The Department's revised adjustment is the result of allocating 99.8 percent to the Minnesota Jurisdiction.[326]

304. MERC agreed with the Department's revised adjustment.[327]

305. The ALJ finds that a two-year amortization period is appropriate in this case. However, if the Commission approves the three-year amortization period recommended by the

[319] Ex. 24 at 15-16 (S. DeMerritt Rebuttal).

[320] Evidentiary Hearing Transcript (May 13, 2014) at 22 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

[321] Ex. 19 at 9-10 (S. DeMerritt Direct); Ex. 40 at 29 (G. Walters Direct).

[322] Ex. 24 at 16-17 (S. DeMerritt Rebuttal).

[323] Ex. 215 at 18-19 (L. La Plante Direct).

[324] Ex. 153 at 1-2, 6 (J. Lindell Rebuttal).

[325] Ex. 24 at 17 (S. DeMerritt Rebuttal).

[326] Ex. 216 at 4-5 and Schedule (LL-S-1) (L. La Plante Surrebuttal).

[327] *See* MERC Issues Matrix at 11 (June 6, 2014) (OAH Docket No. 8-2500-31126, MPUC Docket No. G-011/GR-13-617) (Doc. ID No. 20146-100192-01).

Department, the rate case balance of $257,985 must be debited on an annualized basis and amortization expense credited for the same amount.

306. The ALJ finds that unamortized rate case expenses totaling $1,312,704 and the corresponding related deferred taxes totaling $540,106 should be excluded from rate base.

DD. Charitable Contributions

307. MERC included 2012 actual charitable contributions of $31,050 in its test year income statement.[328]

308. The Department recommended that MERC reduce the test year charitable contributions by $16,105.[329]

309. MERC accepted the Department's recommended reduction of $16,105.[330]

310. The ALJ finds that MERC's Charitable Contributions should be reduced by $16,105 for 2014.

EE. Corporate Aircraft Adjustment

311. The Department recommended that MERC reduce its test year A&G Expense by $956 for corporate aircraft costs.[331]

312. Although MERC continues to believe the corporate aircraft costs are prudent, MERC accepted the adjustment for this proceeding because it is not a material cost.[332]

313. The ALJ finds that MERC's reduction of $956 in A&G expense for corporate aircraft costs should be approved in this rate case.

FF. Transportation Revenue

314. MERC proposed $5,880,151 in transportation sales.[333]

315. The OAG-AUD expressed concern that MERC's projection is not representative of recent history for transportation sales and recommended a $2 million increase in transportation sales to $7,880,151.[334]

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[328] Ex. 19 at 25 (S. DeMerritt Direct); Ex. 24 at 17 (S. DeMerritt Rebuttal); Ex. 4 Initial Filing Volume 3: Informational Requirements, Document 15.

[329] Ex. 215 at 20 (L. La Plante Direct); Ex. 216 at 5 (L. La Plante Surrebuttal).

[330] Ex. 24 at 17 (S. DeMerritt Rebuttal).

[331] Ex. 216 at 6-7 (L. La Plante Surrebuttal); Ex. 215 at 23-24 (L. La Plante Direct).

[332] Ex. 24 at 18 (S. DeMerritt Rebuttal).

[333] Ex. 151 at 14 (J. Lindell Direct).

[334] Ex. 151 at 14 (J. Lindell Direct).

316. MERC disagreed with the OAG-AUD's conclusion. The historical Transport sales that the OAG-AUD analyzed included a non-jurisdictional component, the Michigan Taconite mines. To correct for the Michigan Taconite mines, MERC reduced the Company's total Transport sales for this rate case filing by removing the volumes from the non-jurisdictional customers. MERC notes that the Department's alternative test year Transport forecast would be more appropriate than the OAG-AUD's proposal since it removes the Michigan Taconite mine sales in its analysis.[335]

317. The ALJ finds that MERC's proposed transportation sales forecast in the amount of $6,123,364, updated based on the Department's alternative sales forecast, is appropriate and should be approved in this rate case.

GG. Lobbying Expenses

318. MERC did not have any expenses related to gifts and lobbying. MERC incurs labor costs for employees who engage in lobbying activity, but did not have any external expenses related to lobbying activities.[336]

HH. Research Expenses

319. MERC has not included any research costs in the 2012 historical year. Because recovery of these costs is not requested, no further detail regarding these costs is provided.[337]

II. Interest Synchronization

320. The Department recommended that MERC's test year interest synchronization be adjusted as detailed in the Direct Testimony of Department witness Michelle St. Pierre.[338]

321. MERC accepted this recommendation, but suggested that to the extent the final revenue requirement is different from the position stated in the Department's Direct Testimony, the interest synchronization will change accordingly.[339]

322. The Department agreed to MERC's recommendation.[340]

323. The ALJ finds that MERC's Interest Synchronization should be adjusted pursuant to the Department's Direct Testimony and MERC must recalculate the adjustment as part of MERC's final compliance filing.

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335 Ex. 39 at 2, 12 (H. John Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 106-108 (H. John) (Doc. ID No. 20145-99937-01).

336 Ex. 19 at 49 (S. DeMerritt Direct).

337 Ex. 19 at 25 (S. DeMerritt Direct).

338 Ex. 218 at Schedule (MAS-7) (M. St. Pierre Direct).

339 Ex. 24 at 11 (S. DeMerritt Rebuttal).

340 Ex. 219 at 42 (M. St. Pierre Surrebuttal).

JJ. Regulatory Assets and Liabilities

324. FERC account 182.3 allows for regulatory assets. It states, in part, that:

> A. This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies.

325. MERC initially proposed to include $19,642,806 representing MERC's net regulatory assets in rate base.[341]

326. The Department recommended the removal of $11,281,942 of regulatory assets and liabilities related to seventeen accounts.[342] The majority of the regulatory assets and liabilities the Department proposed to remove from rate base were associated with employee benefits. Of the $11,281,942 proposed adjustment, $11,571,256 related to employee benefits.

327. MERC and the Department are in agreement regarding the treatment of other non-benefit regulatory assets and liabilities.

328. The Department concluded that Account 182901, Cloquet Plant Amortization should not be removed from rate base because in MERC's last rate case, the Commission accepted and adopted the ALJ's findings on this issue and required MERC to include the regulatory asset Cloquet Plant Amortization (Account 182901) in rate base.[343]

329. MERC and the Department agreed that Account 186591 (Account Receivable Arrearage) was erroneously included in rate base and agreed to a rate base reduction of $17,066.[344]

330. MERC and the Department have agreed that because derivative assets were excluded from rate base, Regulatory Liabilities-Derivatives, in the amount of $244,040 (Account 254450) should be excluded as well.[345]

331. MERC also agreed with the Department's proposed adjustment to remove from rate base the recovery of unamortized rate case expense in the amount of $1,315,335 because these costs are not prepaid costs appropriate for inclusion in rate base.[346] MERC proposed an additional adjustment to remove deferred taxes associated with the removed unamortized rate

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341 Ex. 4 Initial Filing Volume 3: Informational Requirements, Document 2, Schedule B-6.

342 Ex. 217 at 9 (M. St. Pierre Direct); Ex. 218 at Schedule (MAS-13) (Attachments to M. St. Pierre Direct); Ex. 219 at 10-11 (M. St. Pierre Surrebuttal).

343 Ex. 217 at 10 (M. St. Pierre Direct).

344 Ex. 24 at 4 (S. DeMerritt Rebuttal); Ex. 217 at 10 (M. St. Pierre Direct).

345 Ex. 24 at 4-5 (S. DeMerritt Rebuttal).

346 Ex. 217 at 11 (M. St. Pierre Direct).

case expense in the amount of $541,188, which the Department agreed was appropriate, but should be adjusted to $540,106 to reflect the amount allocated to Minnesota.[347]

332. Finally, MERC agreed to remove certain amounts pertaining to nonqualified employee benefit costs from rate base. Collectively, this resulted in an increase to rate base of $239,769.[348]

333. The remaining employee benefit related items, taken as a whole, represent the cumulative difference between the contributions funded by MERC to the various benefit trusts and the actuarially calculated expense recognized by MERC.[349]

334. MERC's treatment of the cumulative amount in this rate case is consistent with MERC's treatment in the Company's prior rate case. Although MERC did not include cumulative funding and cumulative expense in its initial filing in the prior rate case, MERC agreed to the inclusion in rate base. Thus, the difference between cumulative funding and cumulative expense was appropriately included in rate base in the last case and is being consistently included in the current case. During the period from 2012 through the 2014 test year, MERC contributed more to the pension and post-retirement benefit trusts than it recognized in expense. This is the primary reason for the proposed rate base adjustment related to employee benefits.[350]

335. MERC and the Department disagreed on the inclusion of Company supplied funds in rate based. MERC proposed to include cumulative excess funding in rate base because MERC's customers will benefit via lower benefit costs and the Department recommended removing $11,508,474 related to employee benefits from rate base.[351]

336. The Department expressed concern that MERC could be receiving a double recovery on benefit assets and liabilities because MERC is already provided recovery for employee benefits in its proposed test year income statement, as well as a return on the employee benefit costs through the lead/lag study. According to the Department, the lead/lag study calculates a receivable or payable amount based on the related test year expense that is added to rate base to earn a return. MERC's regulatory assets and liabilities are receivables and payables. Moreover, receivables and payables or accruals are included in test year income statement expenses and MERC earns a return on those amounts through cash working capital. Thus, the Department believes that including receivables and payables in rate base in addition to cash working capital would provide a second or double recovery of the return on those amounts.[352]

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[347] Ex. 216 at 3-5 (L. La Plante Surrebuttal); Ex. 24 at 17 (S. DeMerritt Rebuttal).

[348] Evidentiary Hearing Transcript (May 13, 2014) at 56 (C. Hans) (Doc. ID No. 20145-99937-01); Ex. 27 at Exhibit CMH-4 (C. Hans Rebuttal).

[349] Ex. 27 at 13 (C. Hans Rebuttal).

[350] Ex. 27 at 13-16 (C. Hans Rebuttal).

[351] Ex. 26 at 8-13, 15-16 (C. Hans Direct); Ex. 27 at 4-17 (C. Hans Rebuttal); Ex. 217 at 7-11, 28-34 (M. St. Pierre Direct); Ex. 219 at 2-4, 7-9, 25-33 (M. St. Pierre Surrebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 23, 54-56, 213-216 (C. Hans and M. St. Pierre) (Doc. ID No. 20145-99937-01).

[352] Ex. 219 at 6 (M. St. Pierre Surrebuttal).

337. MERC disagreed with the Department's position on double recovery. Regulatory assets and liabilities are not a function of benefit expenses. Rather, benefit expenses are a function of assets and liabilities. Typically, the greater the return on assets, the lower the benefit expense MERC recognizes on its income statement. When contrasting the benefits expense with the accounts payable account, which is included in the lead/lag study, MERC recognizes an expense on the income statement at the time of the purchase of materials and supplies, for example, but the invoice itself may not be paid until a later date. The lead/lag study calculates that delay in payment and creates a liability, or reduction in rate base, for that accounts payable expense. Benefit assets and liabilities are more like construction costs than accounts payable. For benefits expenses, MERC must make an out-of-pocket cash expenditure to create the asset, but the asset is then used to earn a return and offset benefit costs. While the benefit asset earns a return, this return is used to reduce benefit costs, not to repay shareholders for their prepayment of benefit costs. Instead, including these assets and liabilities in rate base is how shareholders earn a return on this funding activity.[353]

338. Despite MERC's disagreement with the Department's recommendation, MERC proposed that if the Commission ultimately removes the assets and liabilities associated with the benefits plans, then the corresponding deferred taxes also need to be removed from rate base.[354] The Department agreed with MERC's recommendation. Using information provided by MERC, the Department determined that the deferred tax adjustment amount totals $4,294,542.[355]

339. The Department concluded that Account 182351, Purchase Accounting Effect on Benefits should not be removed from rate base because in Docket No. G007,011/M-06-1287, the Commission authorized MERC to create a regulatory asset for the pension and other post retirements acquired from Aquila.[356]

340. MERC disagreed with the Department's recommendation for all accounts in the 228 range, as well as accounts 242070 and 242072 based on MERC's argument for inclusion of benefit assets and liabilities in rate base.[357] Account 254400 (Regulatory Liabilities Deferred Taxes) should also be included in rate base. To the extent that regulatory assets and liabilities are included in rate base, the associated deferred taxes should also be included in rate base to offset them.[358]

341. At the evidentiary hearing, MERC explained that the Labor Loader regulatory asset (Account 186390), the Injuries & Damages Reserve regulatory liability (Account 228200),

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[353] Ex. 24 at 3-4 (S. DeMerritt Rebuttal).

[354] Ex. 24 at 4 (S. DeMerritt Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 216 (M. St. Pierre) (Doc. ID No. 20145-99937-01).

[355] Ex. 219 at 10-11 (M. St. Pierre Surrebuttal).

[356] Ex. 217 at 10 (M. St. Pierre Direct).

[357] Ex. 24 at 4-5 (S. DeMerritt Rebuttal).

[358] Ex. 24 at 5 (S. DeMerritt Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 216 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

and the Workers Comp Claim Reserve regulatory liability (Account 228210) are all accounts that exist on MERC's balance sheet.[359]

342. In Surrebuttal Testimony, the Department provided a table listing each of the 17 adjustments that it recommended to MERC's regulatory assets and liabilities. MERC agreed to remove two accounts, Deferred Debit-Long Term Account Receivable Average (Account 186591) and Regulatory Liabilities-Derivatives (Account 254450) from rate base. By agreeing to these two adjustments, MERC increased its proposed rate base amount by $226,984. MERC and the Department agreed that Account 186591 was erroneously included in rate base.[360]

	Regulatory Assets	Account Name	MERC Filed	DOC Direct	MERC Rebuttal	DOC Surrebuttal
1	182515	Post retirement Life	$19,777	$0	$19,777	$0
2	182312	FAS 158	$16,587,916	$0	$16,587,916	$0
3	186390	Labor loader	$2,304	$0	$2,304	$0
4	186591	Deferred Dr.-LT A/R	$17,066	$0	$0	$0
5		TOTAL ASSETS	$16,627,063	$0	$16,609,997	$0
	Regulatory Liabilities					
6	228200	Injuries & Damages Reserve	$(217,943)	$0	$(217,943)	$0
7	228210	Workers Comp Claim Reserve	$(6,054)	$0	$(6,054)	$0
8	228300	Deferred Cr-Sup Ret Select(SERP)	$(163,731)	$0	$(163,731)	$0
9	228305	Sup Remp ret Plan (SERP)	$(19,719)	$0	$(19,719)	$0
10	228310	Pension Restoration	$(53,763)	$0	$(53,763)	$0
11	228315	Post Ret Health Care-Admin	$(2,590,545)	$0	$(2,590,545)	$0
12	228320	Post Ret Health Care-NonAdmin	$(749,060)	$0	$(749,060)	$0
13	228331	Accr Pens Liab-CHI Retire Plan	$(1,214,798)	$0	$(1,214,798)	$0
14	242070	Current Pension Obligation	$(20,572)	$0	$(20,572)	$0
15	242072	Current Pension Restoration	$(2,556)	$0	$(2,556)	$0
16	254009	Reg Liab-Cost to Fwd External	$(255)	$0	$(255)	$0

359 Evidentiary Hearing Transcript (May 13, 2014) at 26-30 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

360 Ex. 219 at 4-5 (M. St. Pierre Surrebuttal).

	Regulatory Assets	Account Name	MERC Filed	DOC Direct	MERC Rebuttal	DOC Surrebuttal
17	254400	Reg Liability – Deferred Taxes	$(39,556)	$0	$(39,556)	$0
18	254450	Reg Liability-Derivatives	$(244,050)	$0	$0	$0
19		TOTAL LIABILITIES	$(5,322,602)	$0	$(5,078,552)	$0
20		TOTAL ASSETS/ LIABILITIES	$11,304,461	$0	$11,531,445	$0
21		Minnesota Jurisdiction 99.8007934%	$11,281,942	$0	$11,508,474	$0

343. Based on adjustments agreed to during this proceeding, MERC has proposed to include $18,794,224 of regulatory assets and liabilities in rate base.

344. The ALJ finds that regulatory assets and liabilities in the amount of $18,794,224 should be included in rate base.

KK. Gas Affordability Program ("GAP")

345. Minnesota Statutes Section 216B.16 subsection 15 provides that the Commission must consider ability to pay as a factor in setting utility rates and may establish affordability programs for low-income residential customers in order to ensure affordable, reliable, and continuous service to low-income utility customers. This describes the purpose of MERC's GAP, which was approved by the Commission on February 27, 2008 in Docket No. G007,011/M-07-1131. A four year extension of the program was approved in Docket No. G007,011/M-07-1131, with an expiration date of December 31, 2015.[361]

346. MERC believes the GAP continues to be an excellent program and is highly encouraged by the retention rate. MERC believes the success of GAP indicates that, with a little help, customers are able to make timely payments and the program prevents customers from falling so far behind in their bills that they feel helpless. MERC does not propose any changes to GAP at this time. MERC intends to make any proposals at the end of the GAP on December 31, 2015.[362]

347. The ALJ finds that no changes are needed to MERC's GAP program for purposes of this rate case.

LL. New Area Surcharge

348. The Department recommended that, in a separate proceeding, MERC examine its New Area Surcharge ("NAS"), and assess whether extensions could be made more affordable by extending the surcharge period longer than the current 15 year limit, thereby lowering the annual

[361] Ex. 40 at 30 (G. Walters Direct).

[362] Ex. 40 at 30-31 (G. Walters Direct).

surcharge amount.[363] The Department recommended that MERC provide such a filing as soon as possible.[364]

349. MERC agreed with the Department's recommendation. On June 20, 2014, MERC filed its initial NAS filing for approval of a tariff revision and a new area surcharge for the Ely Lake Project.[365]

350. The ALJ finds that the examination of MERC's NAS in a separate proceeding is appropriate.

MM. Miscellaneous Service Revenues

351. The Department expressed concern with the methodology used by MERC to calculate the Company's miscellaneous service revenues because it was based only on seven months of data. The Department recommended that the test year other revenue from miscellaneous services be increased by $51,493 to more reasonably average the annual revenue over a four-year period of historical data (2010-2013).[366]

352. MERC agreed with the Department's recommended adjustment.[367]

353. The ALJ finds that an increase of $51,493 to MERC's test year other revenue from miscellaneous services is proper in this rate case.

NN. Rate Base Disallowances Relating to Service and Main Extensions

354. In its March 31, 1995, Order in Docket No. G999/CI-90-563, the Commission requested that the Department investigate every gas utility company's service additions to rate base due to new service extensions during a general rate case to make sure: 1) LDCs are applying their tariffs correctly and consistently; 2) that they are appropriately cost and load justified; and 3) that wasteful additions to plant and facilities are not allowed into rate base.[368]

355. MERC conducted the required audit of its main and service extensions to determine whether its extension tariff had been correctly and consistently applied since its last rate case. MERC has removed $29,170 of plant items from its rate base in this rate case proceeding based on MERC's study of compliance with its main and service extensions since the last rate case and proposed adjustments to rate base to reflect these findings.[369] Specifically,

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[363] Ex. 210 at 11-13 (M. Zajicek Direct); Ex. 211 at 5 (M. Zajicek Surrebuttal).

[364] Ex. 211 at 5 (M. Zajicek Surrebuttal).

[365] Ex. 42 at 13 (G. Walters Rebuttal); *see* In the Matter of the Petition of Minnesota Energy Resources Corporation for Approval of a Tariff Revision and a New Area Surcharge for the Ely Lake Project (June 20, 2014) (Doc. ID No. 20146-100673-01).

[366] Ex. 215 at 3 and Schedule (LL-3) (L. La Plante Direct); Ex. 216 at 2 (L. La Plante Surrebuttal).

[367] Ex. 24 at 15 (S. DeMerritt Rebuttal).

[368] *See generally* Ex. 14 (D. Kult Direct); Ex. 210 at 6-7 (M. Zajicek Direct).

[369] Ex. 14 at 3-12 and Schedules (DGK-1 and DGK-2) (D. Kult Direct); Ex. 19 at 28 (S. DeMerritt Direct).

MERC proposed a reduction of $12,859.52 to rate base for service line extensions and a reduction of $16,310.50 to rate base for main extensions.[370]

356. The Department recommended an additional reduction of $6,633.16 to rate base for main and service extensions where customer contributions were not collected, for a total reduction of $35,803.18 for unbilled extension costs.[371]

357. MERC agreed with the Department's recommendation.[372]

358. MERC also provided a quantitative analysis showing that its service-related additions are appropriately cost and load justified. MERC proposed to continue its currently approved 75-foot allowance for each stand-alone service extension and its feasibility model for other residential and all commercial and industrial extensions.[373]

359. The Department recommended that MERC continue to apply the Company's currently approved 75-foot allowance for each stand-alone service line extension, and MERC's currently approved feasibility model for other residential, commercial and industrial extensions.[374]

360. MERC agreed with the Department's recommendation.[375]

361. MERC addressed the issue of whether its extension practices prevent wasteful additions to plant and facilities. MERC's proposed disallowance of $29,170.02 would prevent such additions from being included in this proceeding.[376]

362. The Department determined that appropriate adjustments to correct for errors in MERC's tariff application can be made by applying the $29,170.02 of disallowances proposed by MERC plus the Department's recommended reduction of $6,633.16 for a total of $35,803.18.[377]

363. MERC agreed with the Department's recommendation.[378]

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370 Ex. 14 at 10-11 (D. Kult Direct); Ex. 4 Initial Filing Volume 3: Informational Requirements, Document 2, Schedule B-3.

371 Ex. 210 at 2, 23, 30-31 and Schedules (MZ-1 through MZ-4) (M. Zajicek Direct); Ex. 211 at 1-2 (M. Zajicek Surrebuttal).

372 Ex. 15 at 2-3 (D. Kult Rebuttal).

373 Ex. 14 at 11-12 (D. Kult Direct).

374 Ex. 210 at 10, 26, 31 (M. Zajicek Direct); Ex. 211 at 3 (M. Zajicek Surrebuttal).

375 Ex. 15 at 3 (D. Kult Rebuttal).

376 Ex. 14 at 12 (D. Kult Direct); Ex. 4 Initial Filing Volume 3: Informational Requirements, Document 2, Schedule B-3.

377 Ex. 210 at 25, 27, 31 (M. Zajicek Direct); Ex. 211 at 3 (M. Zajicek Surrebuttal).

378 Ex. 15 at 4 (D. Kult Rebuttal).

364. The ALJ finds that MERC's Service and Main Extension reduction, allowance, and feasibility model are reasonable and should be approved by the Commission.

OO. Rate Base Disallowances Relating to Winter Construction Charges

365. In its Order in Docket No. G007,011/M-07-1188, the Commission required MERC to show in its next general rate case that no winter construction charges were assessed to customers outside of the tariff winter construction charge period and that no winter construction charges incurred by the Company from any contractors outside the tariffed winter construction charge period are proposed to be recovered from other ratepayers. The Commission included similar requirements in its Order after Reconsideration in Docket No. G007,011/GR-08-835.[379]

366. MERC found no invoices for winter charges for work done outside the tariffed Winter Construction Charges period. As a result, MERC removed $0 for winter charges for work done outside the tariffed Winter Construction Charges period.[380] The Department agreed with the disallowance and proposed no further disallowances on winter construction.[381]

367. The Department recommended that MERC continue to show in the Company's rate case that no winter construction costs were assessed outside the winter construction period, and that no winter construction charges incurred by MERC from any contractors outside the winter construction period are proposed to be recovered from other ratepayers.[382]

368. MERC agreed with the Department's recommendations.[383]

369. The ALJ finds that the Commission should accept MERC's proposed rate base disallowance related to winter construction charges.

PP. Rate Base Disallowances Relating to Supplemental Executive Retirement Plan

370. MERC is not seeking recovery of costs associated with the SERP, except those costs that were approved by the Commission in Docket No. G007,011/M-06-1287.[384]

371. The ALJ finds that MERC's recovery of SERP costs approved in Docket No. G007,011/M-06-1287 is appropriate in this rate case.

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[379] Ex. 14 at 13 and Schedule (DGK-3) (D. Kult Direct)

[380] Ex. 14 at 13 (D. Kult Direct); Ex. 19 at 29 (S. DeMerritt Direct).

[381] Ex. 211 at 4 (M. Zajicek Surrebuttal).

[382] Ex. 210 at 27-28 (M. Zajicek Direct); Ex. 211 at 4 (M. Zajicek Surrebuttal).

[383] Ex. 15 at 5 (D. Kult Rebuttal).

[384] Ex. 19 at 32 (S. DeMerritt Direct).

QQ. Rate Base Disallowances Relating to Gas Affordability Program

372. In MERC's last rate case, Docket No. G007,011/GR-10-977, balances associated with the Gas Affordability Program were removed from rate base and, therefore, were removed from rate base in this current rate case.[385]

RR. Test Year Working Capital

373. MERC developed the 2014 test year working capital forecast in this case by adjusting MERC's Working Capital Accounts such that the 2014 proposed working capital would be synchronized with the working capital calculated in the lead/lag study.[386]

374. The Department recommended that MERC's test year working capital be adjusted as detailed in the Direct Testimony of Department witness Ms. St. Pierre (i.e., an increase of $112,753 for the lead/lag adjustment).[387]

375. MERC accepted this recommendation, but suggested that the final cash working capital amount remains in flux until other items in the revenue deficiency calculation are resolved.[388]

376. MERC agreed with the Department's recommendation that in future rate cases MERC provide a schedule that reconciles the expenses in the cash working capital to the expenses in MERC's test year income statement.[389] MERC also agreed with the Department's recommendation that in future rate cases MERC's cash working capital schedule be based on number of days, rather than percentages.[390]

377. The ALJ finds that MERC's Test Year Working Capital adjustment should be adjusted pursuant to the Department's Direct Testimony and MERC must recalculate the adjustment once the other items in the revenue deficiency calculation are resolved.

SS. Intervenor Constellation Issues

378. Intervenor Constellation New Energy – Gas Division, LLC ("Constellation") expressed concern that firm customers are curtailed before all interruptible customers are curtailed. In addition, Constellation requested either confirmation or clarification that gas should be allowed to flow to interruptible customers at any city gate where there are no delivery or

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[385] Ex. 19 at 32 (S. DeMerritt Direct).

[386] Ex. 19 at 8, 33-40 and Schedule (SSD-21) (S. DeMerritt Direct).

[387] Ex. 217 at 50-52 (M. St. Pierre Direct); Ex. 218 at Schedules (MAS-8, MAS-8a) (Attachments to M. St. Pierre Direct).

[388] Ex. 24 at 12-13 and Schedule (SSD-4) (S. DeMerritt Rebuttal).

[389] Ex. 24 at 12 (S. DeMerritt Rebuttal).

[390] Ex. 24 at 12 (S. DeMerritt Rebuttal).

pressure problems even though there could be problems downstream at another city gate that would require firm service to be partially curtailed.[391]

379. MERC explained that Constellation referenced a one-time occurrence and that MERC followed the priority of service as shown in its tariff on 1st Revised Sheet No. 8.41 during that occurrence. MERC declined to confirm Constellation's statement regarding the flow of gas to any city gate. MERC is responsible for providing safe and reliable service to its customers. If, in MERC's opinion, it is necessary to curtail upstream customers to protect service to those downstream, MERC believes it is the Company's right and obligation to protect the reliability of services to all customers pursuant to the tariff requirement. MERC, by default, becomes the provider of service when a customer's or broker's gas does not show up at the city gate.[392]

380. Constellation stated that MERC has no process for reconciling between the interstate pipeline and MERC's distribution system for a customer's firm capacity purchases. Constellation suggested that MERC, upon demand of a customer or a customer's broker, be required to reconcile these differences once each year before the start of the heating season, possibly by October 1 of each year.

381. MERC agreed with Constellation's recommendation with modifications. MERC noted that the Company relies on customers or the customer's broker to provide the Company with the amount of purchased firm capacity on the interstate pipeline and Constellation had not provided such a list to MERC during the past two to three years. MERC expressed its preference that this be an annual process between MERC and the customers and brokers instead of this occurring only on the demand of the customer or broker. MERC prefers that customers and brokers share this information with MERC no later than August 1 of each year in order for MERC to complete the necessary evaluation of its distribution system prior to the start of the heating season.[393]

TT. Uncontested Adjustments

382. MERC filed testimony as part of its application on a number of uncontested financial matters involving various adjustments to the test year. The findings above describe the areas where parties who audited MERC's filing had issues with the treatment of certain amounts and expenses in MERC's filing. No party filed testimony challenging any other aspects of MERC's financial filings. As a result, the uncontested portions of MERC's filing should be approved.

UU. Revenue Requirements Summary

383. With the adjustments to rate base and test year operating expenses and revenues agreed to by the parties through the course of testimony exchanged in this proceeding, MERC

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[391] *See generally* Ex. 125 (R. Haubensak Direct).

[392] Ex. 42 at 14-15 (G. Walters Rebuttal).

[393] Ex. 42 at 16-17 (G. Walters Rebuttal).

calculates the gross revenue deficiency to be $12,159,454.[394] The Department calculates the gross revenue deficiency to be $3,480,421.[395]

384. These numbers are approximate, and because of the changes from the initial filing, the numbers need to be recalculated to reflect the agreement of the parties as to certain issues and the recommended return on common equity established in these findings. As a result, while an estimated figure is provided in these findings, the concepts embodied in these findings should govern. The Commission is in a better position to produce a final calculation of the revenue deficiencies once it makes its final determination in this case.

III. Conservation Improvement Program and Cost Recovery Mechanisms

385. MERC has an approved CIP on file with the Department of Commerce.[396]

386. The legislature requires utilities to make certain CIP expenditures pursuant to Minn. Stat. § 216B.241, and it has established a requirement for cost recovery of these expenses in utility rates. Minn. Stat. § 216B.16, subd. 6b, mandates recovery of CIP expenses in utility rates, and allows a public utility to file rate schedules providing for annual recovery of the cost of CIP programs.

387. Specifically, Minn. Stat. § 216B.16, subd. 6b(a) allows utilities to recover costs of relevant conservation improvements:

> Except as otherwise provided in this subdivision, all investments and expenses of a public utility . . . incurred in connection with energy conservation improvements shall be recognized and included by the commission in the determination of just and reasonable rates as if the investments were directly made or incurred by the utility in furnishing utility service.

388. In the 2010 rate case, MERC received Commission approval to implement a Conservation Cost Recovery Adjustment ("CCRA") factor to recover the amount by which actual CIP expenditures are different from the amount recovered through the CCRC factor plus the amount of any Commission-approved CIP financial incentive on an annual basis.[397]

389. The Commission initially set the CCRA factors for MERC-NMU and MERC-PNG at $0.0000 per therm. MERC's request to update the CCRA factors set in the last rate case was approved by the Commission in G011/M-10-407 and G007/M-10-409 on October 11, 2010. The current CCRA factor is $0.0000 per therm for MERC-NMU and $0.0420 for MERC-PNG. The Commission approved a CCRA of $0.00475 for MERC-NMU effective January 1, 2014. MERC stopped collecting the CCRA factor for NMU customers effective with May 2014 billing

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394 Ex. 24 at 30 (S. DeMerritt Rebuttal).

395 Department Summary of Issues at Schedule 3 (Dec. 14, 2011) (Doc. ID No. 20146-100192-01).

396 Ex. 19 at 41 (S. DeMerritt Direct); Ex. 217 at 12 (M. St. Pierre Direct).

397 Ex. 19 at 41-42 (S. DeMerritt Direct).

because the MERC-NMU CIP tracker balance reached zero. On May 1, 2014, MERC proposed a consolidated CCRA factor of $0.00148 to be effective January 1, 2015. The Commission has yet to issue and Order approving MERC's proposed consolidated CCRA factor.[398]

A. CIP Tracker Account Balances

390. Based on Department recommendations related to test year CIP expenses, MERC determined that a slight adjustment will need to be made to the CIP tracker at the time of final rates. Currently, in interim rates, MERC is collecting revenue from customers and crediting the CIP tracker balance at MERC's filed CCRC of $0.02432. If MERC's CCRC of $0.02462, as recommended in MERC's Rebuttal Testimony, is approved in this proceeding, MERC will have under-collected CIP expense during the time frame that the Company's interim rates were in effect. In the event that a CCRC of $0.02462 is approved and MERC has under-collected CIP expense, MERC recommends crediting the CIP tracker balance (Account No. 182705) by $0.00030 ($0.02462 - $0.02432) x actual sales during the period interim rates were in effect, and debiting the CIP Amortization account (Account No. 407710) for this same amount. This adjustment would increase MERC's CIP expenses that should have been recognized during interim rates, which would be offset by a lower refund to customers because of the higher revenue requirement generated by the increased CIP expenses.[399]

391. The Department concluded that MERC's request to credit the CIP tracker balance in the event MERC under collects CIP expense during interim rates is reasonable.[400]

392. The ALJ finds that MERC's request to credit the CIP tracker balance in the event MERC under collects CIP expense during interim rates is reasonable.

B. Test Year CIP Expenses

393. MERC proposed to include CIP expenses in the Company's base rates via the test year in this proceeding. Initially, MERC proposed to include in the test year CIP expenses of $8,920,481 in rate base.[401]

394. The Department recommended increasing CIP expense in this case from the $8,920,481 initially proposed by MERC to $9,396,422 to reflect approved 2014 CIP expense. The Department also recommended that MERC's CCRC be recalculated based on the Commission's Order regarding the level of CIP expenses divided by the approved level of sales.[402]

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[398] Ex. 19 at 42 (S. DeMerritt Direct); *see also* Docket No. G011/M-14-369 (2013 Consolidated CIP Tracker Account, DSM Financial Incentive, and Conservation Cost Recovery Adjustment).

[399] Ex. 24 at 7-8 (S. DeMerritt Rebuttal).

[400] Ex. 219 at 18 (M. St. Pierre Surrebuttal).

[401] Ex. 19 at 10, 41-44 and Schedule (SSD-24) (S. DeMerritt Direct).

[402] Ex. 217 at 14, 16 (M. St. Pierre Direct); Ex. 219 at 11 (M. St. Pierre Surrebuttal).

395. MERC agreed to the increase in CIP expense as proposed by the Department. MERC recalculated the CCRC using the Department's recommended update to CIP expense and the CCRC-applicable sales. A CCRC rate of $0.02462 was calculated, which is $0.00949 greater than MERC's CCRC approved in Docket No. G007,011/GR-10-977.[403]

396. The Department recommended that the test year CIP revenue be increased to the level of CIP expense approved in the test year to be revenue neutral. According to the Department, in MERC's proposed rate case, the sales revenue that is related to the base cost of gas is treated differently than CIP revenue. MERC does not include the cost of gas in the revenue requirement because the test year sales revenue related to gas costs is matched to the projected gas costs rather than calculated at present rates. CIP, on the other hand, is in the revenue requirement because the test year sales revenue is calculated at present rates rather than forecasted final rates. The Department recommended using the same method for CIP costs as used for gas costs, since both cost categories have trackers that run through rate cases and subsequent to rate cases. Thus, the Department recommended that a new CCRC be implemented at the beginning of the rate case as well as at final rates. The Department recommended increasing natural gas revenue by $3,758,090 in relation to CIP expense.[404]

397. MERC disagreed with the Department's recommendation. By imputing CIP revenues of $3,758,090 to offset the increase in CIP expense, the Department effectively reduced MERC's revenue requirement based on revenue that will never be collected.[405] At the evidentiary hearing, MERC explained that the Department's recommended increase incorrectly lowers the revenue deficiency while the expenses related to CIP actually increases. In other words, the Department is recommending an overall rate increase of $3.3 million, while CIP expenses alone are increasing $3.8 million. This has the effect of reducing rates $500,000 for all of MERC's other costs included in this case.[406]

398. Because MERC has increased CIP recovery since the beginning of interim rates and, at the end of the rate case, when final rates are implemented, the CCRC factor would change to reflect the Commission's Order on CIP expenses and CIP-related sales, the Department disagreed that MERC would never collect the revenue.[407]

399. Based on subsequent discussions between MERC and the Department following the submission of the Department's Direct Testimony, MERC understood that the Department's ultimate goal was to remove the CCRC from base rates completely, thereby allowing all CIP expenses to flow through the CCRA. In order to accomplish this, MERC understood the Department to propose that MERC remove all CIP expenses from the revenue deficiency.

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[403] Ex. 24 at 6-7 (S. DeMerritt Rebuttal).

[404] Ex. 217 at 15 (M. St. Pierre Direct); Ex. 219 at 12-14 (M. St. Pierre Surrebuttal).

[405] Ex. 24 at 5-8, 13-14 and Schedule (SSD-2) (S. DeMerritt Rebuttal).

[406] Evidentiary Hearing Transcript (May 13, 2014) at 23 (S. DeMerritt) (Doc. ID 20145-99937-01).

[407] Ex. 219 at 14 (M. St. Pierre Surrebuttal).

MERC would then seek recovery for any under-collection of CIP expenses via a separate docket filed for the CCRA.[408]

400. MERC testified that it would not be opposed to this approach provided that the dockets related to the CCRA are finalized and an order is issued in a timely fashion. In addition, if changing the CCRC to $0.00000 were to occur in the current docket, MERC would request that its currently recommended CCRC of $0.02462 be added to the CCRA on January 1, 2015, or with implementation of final rates, whichever occurs later, so as not to delay the recovery of these expenses.[409]

401. In Surrebuttal Testimony, the Department stated that its recommendation is not to remove the CCRC from base rates completely, thereby allowing all CIP expenses to flow through the CCRA. Rather, the Department's recommendation is to set the CIP revenue equal to the CIP expense so that final rates would include CIP revenue and CIP costs of $9,396,422.[410] In the alternative, the Department suggested that MERC could remove CIP completely from base rates, so total CIP revenue and total CIP expenses would both be set at zero for present rates, interim rates, and final rates. Although MERC stated that it would not be opposed to this approach, the Department does not recommend this method because it is easier to understand and accept if the CCRC is determined similar to the way that base cost of gas is determined.[411]

402. The ALJ finds that the Department's proposed adjustment to revenue based on MERC's updated CIP expense would not be revenue neutral and is not justified. The ALJ concludes that MERC's proposed CIP expense of $9,396,422 should be accepted.

C. Carrying Charges for CIP Tracker Accounts

403. MERC proposes a carrying charge equal to the overall rate of return approved in the instant case.[412]

404. The Department recommended that MERC update its CIP tracker carrying charge to the rate of return that is approved in this general rate case.[413]

405. MERC agreed with the Department's recommendation.[414]

406. The ALJ finds that MERC's proposed carrying charge is appropriate in this rate case.

[408] Ex. 24 at 6 (S. DeMerritt Rebuttal).

[409] Ex. 24 at 6 and Schedule (SSD-1) (S. DeMerritt Rebuttal).

[410] Ex. 219 at 14 (M. St. Pierre Surrebuttal).

[411] Ex. 219 at 15-16 (M. St. Pierre Surrebuttal).

[412] Ex. 19 at 43 (S. DeMerritt Direct).

[413] Ex. 217 at 15 (M. St. Pierre Direct).

[414] Ex. 24 at 13 (S. DeMerritt Rebuttal).

D. CIP Exempt Customers

407. A "CIP-exempt customer" is a customer that has been granted an exemption by the Commissioner of the Department from paying for, or participating in, the CIP projects offered by the utility providing retail electric or gas service to that facility, pursuant to Minn. Stat. § 216B.241.

408. MERC recently discovered that a significant Taconite customer, Northshore Mining, has, in error, been continuously treated as exempt from the CIP charges dating back at least to the days of Aquila's gas operations (MERC's predecessor). Upon discovery of this error, MERC notified Northshore and Northshore applied for a CIP exemption. MERC will absorb this under recovery and not seek the one-year back payment of CIP charges allowed by the billing error rules. Northshore is a SLV transportation customer whose gas is directly supplied by Northern Natural Gas's interstate pipeline. Accordingly, Northshore is a very serious bypass threat. MERC prepared the test year CIP schedules assuming Northshore would be granted an exemption.[415]

409. The Department noted that Northshore's CIP petition for exemption was granted effective January 1, 2014.[416] The Department recommended a one-time carrying charge be applied to the unrecovered CIP balance. For the carrying charge rate, the Department recommended use of MERC's approved overall rate of return in effect during the period of under collection (July 2006 through December 2013). The Department recommended that the Commission require MERC to credit the CIP tracker for uncollected amounts (CCRC and CCRA) from July 2006 through December 2013 before Northshore's CIP exemption was effective January 1, 2014. The Department also recommended that the Commission require MERC to report this information in its final rates compliance filing in the present docket.[417]

410. MERC agreed with the Department's recommendations.[418]

411. At the evidentiary hearing, MERC reiterated that it would absorb this under recovery and not seek the one-year back payment of CIP charges allowed by the billing error rules. MERC also confirmed that the Company is analyzing the situation by going back and reviewing its similarly-situated customers that could be CIP exempt, as well as making sure it more clearly identifies the customers that are CIP exempt to prevent this situation from happening again.[419]

412. The ALJ finds that, given MERC's willingness to absorb the under-recovery related to Northshore, credit the CIP tracker for the uncollected amounts and continue to improve

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[415] Ex. 19 at 44 (S. DeMerritt Direct); Evidentiary Hearing Transcript (May 13, 2014) at 35-36 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

[416] Ex. 217 at 19 (M. St. Pierre Direct).

[417] Ex. 217 at 20-21 (M. St. Pierre Direct).

[418] Ex. 24 at 13-14 (S. DeMerritt Rebuttal).

[419] Evidentiary Hearing Transcript (May 13, 2014) at 36-37 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

the Company's billing system to properly identify CIP exempt customers, the Commission should approve MERC's approach to uncollected CIP expense in this rate case.

E. Calculation of Conservation Cost Recovery Charge ("CCRC")

413. In MERC's last rate case, MERC inputted revenues to offset the increase in CIP expense due to an increased CCRC for interim rate purposes. This created a revenue neutral effect in interim rates for purposes of the increased CCRC, but created confusion among the parties. Therefore, prior to this current rate case, MERC contacted Commission staff to work on how to address the increase in the CCRC in interim rates. Commission staff gave the guidance that MERC should include the increased expense in the interim rate calculation, so that is the approach that MERC took in this current docket.[420]

414. MERC proposed a CCRC of $0.02432 per therm.[421] In addition, MERC agreed to credit the CIP tracker inclusive of carrying charges related to the Northshore Mining issue.[422]

415. The Department initially expressed concern that MERC had not changed its CCRC factor to reflect the CIP recovery from interim rates.[423] The Department recommended MERC update the CCRC rate based on the Commission order in MERC's final rates compliance filing, and recommended that MERC do so at the beginning of interim rates and again at final rates.[424]

416. MERC agreed with the Department's recommendation. In particular, MERC noted that it has already updated the CCRC rate for interim rate and has recognized the increased CIP amortization expense associated with the higher rate that is being collected in the Company's current revenues. MERC is willing to update the CCRC in final rates based on the higher CIP expense and change in sales forecast from filing, along with making a CIP tracker balance adjustment.[425]

417. In Surrebuttal Testimony, the Department concluded that MERC had provided evidence to show that the Company increased its CCRC factor when interim rates were implemented on January 1, 2014.[426]

418. The ALJ finds that MERC's CCRC is reasonable and should be approved, contingent on MERC updating the CCRC in final rates and making a CIP tracker balance adjustment.

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[420] Ex. 19 at 44 (S. DeMerritt Direct).

[421] Ex. 19 at Schedule (SSD-24) (S. DeMerritt Direct).

[422] Ex. 24 at 8 (S. DeMerritt Rebuttal).

[423] Ex. 217 at 16 (St. Pierre Direct).

[424] Ex. 217 at 17 (St. Pierre Direct); Ex. 219 at 17 (M. St. Pierre Surrebuttal).

[425] Ex. 24 at 13 and Schedule (SSD-2) (S. DeMerritt Rebuttal).

[426] Ex. 219 at 16 (M. St. Pierre Surrebuttal).

F. Responses to Commission Requests for Additional Information

419. In the Commission's November 27, 2013, Notice and Order for Hearing, the Commission asked MERC to address various CIP items in further detail. Accordingly, MERC provides information regarding the Commission's questions related to CIP and associated rates, as well as the effect of an updated sales forecast and commodity pricing forecast on the demand and commodity cost of gas rates.[427]

420. The Commission asked MERC for the following information:

- A calculation of the CCRC and the CCRA charge since the inception of MERC's ownership;
- The applicable Northshore volumes, CCRC and CCRA rates, and CCRC and CCRA amounts, by month, for the period July 2006 through December 31, 2013;
- Information on the adequacy of the Vertex billing audit with respect to finding CIP-related and other billing errors;
- Information on the tracking and handling of CIP expenses in the development of the test year operating expenses; and
- The potential impact of updated sales and forecast and commodity pricing forecast updates on the demand and commodity cost of gas rates.[428]

421. The calculations for the CCRC and CCRA since the inception of ownership of MERC by Integrys are provided in MERC witness Seth DeMerritt's Supplemental Direct Exhibit SSD-1.[429]

422. The volumes for Northshore, the CCRC and CCRA rates and amounts, by month, from July 2006 through December 2013 are provided in Mr. DeMerritt's Supplemental Direct Exhibit SSD-2.[430]

423. Regarding the Vertex audit, as indicated in the May 1, 2013 briefing papers filed in Docket No. G007,011/GR-10-977, MERC worked with the Department and the OAG on a Statement of Work ("SOW") related to an audit of the Vertex billing system. No audit tests specifically related to CIP issues were explicitly identified in the SOW. Thus, to the extent that any billing errors related to CIP were not discovered in the audit process, no specific CIP issues

[427] Ex. 21 at 2 (S. DeMerritt Supplemental Direct); Ex. 22 at Schedules (SSD-1 through SSD-3) (Exhibits to S. DeMerritt Supplemental Direct).

[428] Ex. 21 at 3 (S. DeMerritt Supplemental Direct).

[429] Ex. 21 at 3 (S. DeMerritt Supplemental Direct); Ex. 23 at Schedule (SSD-1) (Exhibits to S. DeMerritt Supplemental Direct).

[430] Ex. 21 at 4 (S. DeMerritt Supplemental Direct); Ex. 23 at Schedule (SSD-2) (Exhibits to S. DeMerritt Supplemental Direct).

were specifically sought out. The results of the billing audit were submitted on October 12, 2012 with no significant issues, but MERC did note that the revenue deficiency in Docket G007,011/GR-10-977 would have been reduced by $9,710. In accordance with Commission Order, MERC has reduced the revenue deficiency in this current docket by that amount inclusive of carrying charges.[431]

424. Regarding MERC's tracking and handling of CIP expenses in the development of the test year operating expenses, the test year operating expenses included in the test year for CIP were the 2013 expenses approved in Docket No. G007,011/CIP-12-548. Per MERC's response to Department Information Request 105, MERC more appropriately should have used the 2014 proposed CIP expenses in developing the test year operating expenses.[432]

425. Regarding the potential impact of updated sales and forecast and commodity pricing forecast updates on the demand and commodity cost of gas rates, historically any change in the sales forecast has not had an effect on the demand or commodity gas rates within a rate case proceeding. To the extent that commodity pricing was changed, the associated commodity gas rates were adjusted accordingly, with no change to the demand rates.[433]

IV. RATE DESIGN

426. In the rate design portion of a general rate case, the Commission determines what portion of the revenue requirement should be met by the various customer classes that receive service from the utility company. This division of responsibility for producing the required revenues among the customer classes is called revenue apportionment. In addition to revenue apportionment, the Commission considers how to design the rates within each customer class to collect the amount of revenue that has been apportioned to that class.

427. As a starting point, the Commission utilizes an analysis of the class cost of service, which evaluates both the cost imposed by each customer class as a whole, and also determines the cost of each relevant component of service that is separately charged by the Company's tariffs.

428. In the rate design phase of the proceeding, the Commission considers cost, as well as other non-cost factors, in designing final rates for the utility. These rates must be designed to recover the revenue requirement that has been determined for the utility, and thus when non-cost factors are applied to reduce a rate for one class, the revenues need to be collected in some manner from other customer classes. Similarly, when different types of costs imposed by one class of customers are not recognized in one part of that customer class's rates, those costs must then be recovered by other components of that customer class's rates.

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[431] Ex. 21 at 4 (S. DeMerritt Supplemental Direct).

[432] Ex. 21 at 4-5 (S. DeMerritt Supplemental Direct); Ex. 23 at Schedule (SSD-3) (Exhibits to S. DeMerritt Supplemental Direct).

[433] Ex. 21 at 5 (S. DeMerritt Supplemental Direct).

A. Class Cost of Service Study

429. The purpose of a Class Cost of Service Study ("CCOSS") is to identify the revenues, costs and profitability for each class of service, as required by Minn. R. 7825.4300(C). The CCOSS analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes.[434]

430. In its initial filing, MERC presented its CCOSS for the entire Minnesota service territory. This CCOSS applied general principles of cost allocation from both the National Association of Regulatory Utility Commissioners ("NARUC") and the American Gas Association ("AGA") to arrive at estimated costs of service for the various customer classes and individual components of cost within each customer class.[435]

431. Based on MERC's CCOSS, the Company determined that 68.3 percent of its distribution mains should be classified as customer costs and 31.7 percent should be classified as demand costs.[436]

432. The OAG-AUD reviewed the CCOSS filed by MERC and concluded that MERC's zero-intercept analysis violated multiple econometric assumptions that resulted in MERC incorrectly estimating its Mains account distributions. The OAG-AUD recommended that the Commission disregard MERC's zero-intercept analysis and require the Company to improve its model in the next rate case.[437] In addition, the OAG-AUD recommended a 30 percent customer classification for the Mains account and that MERC make the following changes to the Company's zero-intercept study:

- Take into account more variables;
- Maintain data at the project level;
- Do not aggregate or average data; and
- Change the percentages used to classify MERC's distribution mains (based partially on the results of a zero-intercept study the OAG-AUD performed and partially on the results of other zero-intercept studies of other utility companies in other states).[438]

[434] Ex. 29 at 5 (J. Hoffman Malueg Direct).

[435] Ex. 29 at 7 (J. Hoffman Malueg Direct).

[436] Ex. 30 at 19 (J. Hoffman Malueg Rebuttal).

[437] Ex. 155 at 34 (R. Nelson Direct).

[438] Ex. 155 at 2-3, 16, 34-36 (R. Nelson Direct).

The OAG-AUD acknowledged that the CCOSS is a subjective tool but focused its attention on the classification of the Distribution mains account because it is MERC's largest investment in the Company's entire distribution plant.[439]

433. MERC disagreed with the OAG's recommendations. The OAG-AUD's calculations are based on a theoretical, not realistic, equation and MERC already considers many of the variables recommended by the OAG-AUD in the Company's zero-intercept analysis. Those variables that were not included were omitted due to limited data availability.[440] Maintaining data at the project level simply for purposes of a rate case zero-intercept study is neither practical nor cost justified. Gathering of MERC's historical distribution main data would be time-intensive and/or would require MERC to invest in costly Information Technology assets. MERC has not been required to maintain this level of detail information in the past nor, to MERC's knowledge, is its collection required of other Minnesota utilities, a point which the OAG-AUD concedes.[441] Despite the OAG-AUD's statement that project level data is collected by other Minnesota utilities, the OAG-AUD was only able to identify one Minnesota utility, CenterPoint Energy, which collects the type of data the OAG-AUD considers to be project level data.[442]

434. MERC conducted three minimum size studies on the Company's distribution mains. The first study, which used a 2" main as the minimum standard for installation, resulted in a distribution main classification of 74.1 percent to customer and 25.9 percent to demand. The second study, which utilized a 2" main as the minimum standard for installation, as well as aggregates pipe sizes less than 2" in diameter with the 2" sized pipes, resulted in a distribution main classification of 73.2 percent to customer and 26.8 percent to demand. These two minimum size studies demonstrated the reasonableness of the results of MERC's zero-intercept study.[443] The third minimum size study contained information from a minimum size study performed by MERC on the Company's distribution mains that did not consider MERC's minimum installation standards. The study was provided to illustrate the extreme results that can occur when minimum installation standards are not considered and illustrates why MERC views the third study as inappropriate for the current rate case.[444]

435. MERC disagreed with the OAG-AUD's recommendation that MERC not aggregate or average data in the Company's zero-intercept study. The OAG-AUD's recommendation is not practical given MERC's distribution main data and application of the zero-intercept study results in MERC's CCOSS. The purpose of the zero-intercept study is to provide a hypothetical zero-load or zero-sized distribution main on MERC's entire system. The end result of this analysis is then used to classify MERC's distribution mains as an entire system, separating the distribution mains between the classifications of customer and demand.

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439 Ex. 155 at 5-6 (R. Nelson Direct).

440 Ex. 30 at 4-9 (J. Hoffman Malueg Rebuttal).

441 Ex. 30 at 5-13 (J. Hoffman Malueg Rebuttal); Ex. 158 at 6 (R. Nelson Surrebuttal).

442 Ex. 155 at 17 (R. Nelson Direct); Ex. 158 at 6 (R. Nelson Surrebuttal).

443 Ex. 30 at 13-17 and Schedule (JCHM-3) (J. Hoffman Malueg Rebuttal).

444 Ex. 30 at 3 and Schedules (JCHM-1 and JCHM-4) (J. Hoffman Malueg Rebuttal).

NARUC's guidance is to use average unit costs when conducting a zero-intercept analysis. Finally, both the NARUC Electric Manual and the NARUC Gas Distribution Rate Design Manual state, and the OAG-AUD's own Direct Testimony implies, that the minimum size and zero-intercept analyses will have similar results and that a minimum size analysis utilizes the average cost of data. Therefore, it only makes sense that, if done properly, in order for a minimum size analysis and a zero-intercept analysis to have comparable results, both must utilize average unit cost.[445]

436. Based on a zero-intercept study performed by the OAG-AUD and zero-intercept analyses completed in other jurisdictions, the OAG-AUD recommended changing the classification percentages applied to MERC's distribution assets in the CCOSS to 30.0 percent customer and 70.0 percent capacity.[446]

437. MERC disagreed with the OAG-AUD's recommendation for a number of reasons. First, MERC properly used average unit costs in its analysis. Second, MERC properly considered MERC's standard installation practices in its analysis. MERC does not feel it is appropriate to conduct the zero-intercept analysis, or a minimum size analysis, without considering the current minimum installation practices. MERC's installation standards consider current industry standards and practices, safety measures, as well as what is most appropriate given MERC's service territory. Third, MERC noted that the results of MERC's third minimum size study, which MERC feels is inappropriate, produces results that are similar to the recommendations made by the OAG-AUD. Finally, MERC determined that the negative values in Exhibit REN-13 from the OAG-AUD's Direct Testimony clearly demonstrated that the results of its zero-intercept analysis are not appropriate. Contrary to the OAG-AUD's conclusions, there are fixed and variable costs associated with both plastic and steel distribution mains. Moreover, to have a negative coefficient of the size-squared variable is equivalent to stating that there is a negative-sized pipe diameter, which is an obvious error in the OAG-AUD's analysis. The OAG-AUD's choice to completely exclude steel distribution main costs from the minimum system study ignores actual installation practices. To conduct a minimum system study that does not consider that steel main can be, and is, just as much a minimum installation requirement as plastic, is erroneous.[447]

438. Regarding the zero-intercept analyses completed in other jurisdictions, MERC does not feel they offer a sound basis for the OAG-AUD's recommended change to the classification percentages applied to MERC's distribution mains. MERC has its own distinct service territory, comprised of its own unique customers and their associated demands, unique geographic terrain, and, accordingly, its own unique distribution system requirements on which the Company's distribution main installations have been based. For this reason, it is illogical to compare the minimum system analyses performed by other gas utilities in other parts of the nation to MERC's system analysis. In addition, individual state regulation and/or different processes or steps taken by these utilities when conducting their studies could impact the results of those studies, making them inapplicable to MERC. There is no guarantee that comparison of

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[445] Ex. 30 at 17-19 (J. Hoffman Malueg Rebuttal).

[446] Ex. 155 at 37-40 (R. Nelson Direct); Ex. 158 at 10-12, 17-18 (R. Nelson Surrebuttal).

[447] Ex. 30 at 19-23 and Schedule (JCHM-4) (J. Hoffman Malueg Rebuttal).

MERC's zero-intercept study results would be an apples-to-apples comparison to the utilities listed in the OAG-AUD's Exhibit REN-16. Thus, to rely on such a comparison, and to potentially base MERC's customer rates on the analyses, would be unsupportable and unwise.[448]

439. MERC's zero-intercept study is based on data that is available, complete, and relevant to the analysis. As stated in MERC's responses to the OAG-AUD's utility information request numbers 700, 702, 703, 704 and 711, the assumptions, specifications, and statistical techniques utilized by MERC in its zero-intercept study are similar to and consistent with those used by Integrys subsidiaries other than MERC.[449]

440. Based on the drastic difference between the OAG-AUD's distribution main classifications and MERC's distribution main classifications, the Department requested that MERC use another method, the minimum size method, to classify the Company's distribution mains. MERC's minimum size analysis showed that at least 73 percent of the distribution mains would be classified as customer costs under the minimum size method. As a result, the Department recommended no change in MERC's proposed classification of distribution mains.[450]

441. The Department and MERC agreed on MERC's allocation of Account 902: Meter Reading Expense.[451]

442. The OAG-AUD and MERC initially disagreed regarding the allocation of Account 902.[452] However, the OAG-AUD later rescinded its objection to MERC's allocation methodology.[453]

443. The Department and MERC agreed on MERC's allocation of Account 903: Customer Records & Collection Expense.[454]

444. The OAG–AUD recommended that MERC allocate Account 903 based on a weighted customer allocator.[455]

445. MERC disagreed with the OAG-AUD's recommendation. The allocation method recommended by the OAG-AUD is based on a customer count allocation method that is weighted by the average cost per customer for meters in each respective rate schedule. The OAG-AUD's recommendation does not provide an accurate cost causation representation. The

[448] Ex. 30 at 23-25 (J. Hoffman Malueg Rebuttal).

[449] Evidentiary Hearing Transcript (May 13, 2014) at 68-69 (J. Hoffman Malueg) (Doc. ID No. 20145-99937-01); Ex. 32 (IR Response 700); Ex. 33 (IR Response 702); Ex. 43 (IR Response 703); Ex. 34 (IR Response 704); Ex. 35 (IR Response 711).

[450] Ex. 208 at 11-12 and Schedule (SO-R-4) (Ouanes Rebuttal).

[451] Ex. 208 at 6-8 (S. Ouanes Rebuttal).

[452] Ex. 30 at 26-31 (J. Hoffman Malueg Rebuttal); Ex. 155 at 40-43 (R. Nelson Direct).

[453] Ex. 158 at 19 (R. Nelson Surrebuttal).

[454] Ex. 208 at 8-10 (S. Ouanes Rebuttal).

[455] Ex. 155 at 3, 41-42 (R. Nelson Direct); Ex. 158 at 19-20 (R. Nelson Surrebuttal).

costs in Account 903 are costs associated with labor, materials, and expenses related to working on customer applications, contracts, orders, credit investigations, billing and accounting, collections, and complaints.[456]

446. MERC recognizes that transportation customers require more account administration and should be allocated more Account 903 costs than a sales customer. MERC incurs additional costs from its transportation customers, and appropriately allocates those costs to those customers. After removing the costs from administering MERC's transportation program, the remaining costs in Account 903 are primarily related to MERC's employment of Vertex, and external service provider, to perform MERC's customer service and billing functions for all of MERC's customers. There is no merit to the OAG-AUD's argument that other Minnesota gas utilities factor in class complexity when allocating Account 903 because Vertex charges MERC a flat, per account, rate to perform customer services and there is no difference in the flat rate charge amongst the different types of MERC customers. Even assuming the OAG-AUD is correct that using a meters weighted allocator for Account 903 is recommended by the NARUC in the NARUC gas manual, the OAG-AUD's recommendation has no merit in this case. The NARUC gas manual, while a good tool for guidance on cost of service allocations, was created in 1989, when a utility outsourcing its customer information systems function was rarely the "norm." While the NARUC Gas Manual may be appropriate for a gas utility that performs its own customer information systems and services function, it is not appropriate for MERC.[457]

447. MERC allocated the Company's income taxes on the basis of rate base, which was mathematically equivalent to allocating the income taxes on the basis of taxable income by class that fully and only reflects the CCOSS.[458]

448. The Department expressed only one concern with MERC's CCOSS; the Company's allocation of income taxes by class.[459] The Department determined that the proposed CCOSS appeared to allocate income taxes on the basis of rate base and agreed with the OAG-AUD that income taxes should instead be allocated on the basis of the taxable income attributable to each customer class. However, the Department was able to verify that allocating income taxes by class on the basis of taxable income that fully and only reflects the CCOSS resulted in an allocation identical to a rate base allocation and concluded that MERC's proposed allocation of income taxes by class was reasonable under MERC's current circumstances. The Department recommended that the Commission accept MERC's proposed CCOSS as a useful tool for the purpose of setting rates. The Department also recommended that the Commission require MERC in future rate cases to calculate and allocate income taxes by class, on the basis of taxable income by class that fully and only reflects the CCOSS.[460]

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456 Ex. 30 at 32-33 (J. Hoffman Malueg Rebuttal).

457 Ex. 30 at 33-35 (J. Hoffman Malueg Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 70-71 (J. Hoffman Malueg) (Doc. ID No. 20145-99937-01).

458 Ex. 29 at 4 (J. Hoffman Malueg Direct); Ex. 4 Initial Filing Volume 3: Informational Requirements, Document 2, Schedules 1 and 9.

459 Ex. 206 at 10 (S. Ouanes Direct).

460 Ex. 206 at 10-13 (S. Ouanes Direct); Ex. 208 at 2-3, 6 (S. Ouanes Rebuttal).

449. The OAG-AUD disagreed with MERC's and the Department's conclusions regarding the calculation of income taxes. The OAG-AUD expressed concern that, contrary to Commission requirements, MERC allocated the Company's income taxes to customer classes based on rate base instead of taxable income. The OAG-AUD argued that allocating income taxes by class that fully and only reflects the class cost of service study means that revenues are not considered to determine taxable income because the class cost of service study only allocates costs. The OAG-AUD recommended that MERC comply with the intent of the Commission's prior decisions and allocate income taxes for each class using the same methodology as MERC calculates income taxes for the total Minnesota jurisdiction. The OAG-AUD recommended that the approach to calculation of income taxes should be the same for total company and individual classes, i.e., income taxes should be calculated and assigned to customer classes based on taxable income for each class that reflects revenues and expenses for each class.[461] The Department was able to determine that the tax rate across customer classes was the same as the tax rate applied to the Minnesota jurisdiction.[462]

450. MERC does not claim that allocating income taxes based on rate base is the same as allocating on taxable income. Income taxes should be allocated on the basis of taxable income by class that fully and only reflects the CCOSS. MERC has shown through Informational Requirements Document 12, Schedule 9, that allocating income taxes on the basis of taxable income by class that fully and only reflects the CCOSS is mathematically equivalent to a proportion of rate base. MERC allocates income taxes by using the rate base allocation methodology, which the Company believes is the most appropriate allocation method. MERC did comply with the intent of prior Commission decisions. The Commission, in Docket No. G-007,011/GR-08-835, through its incorporation of the agreement between MERC and the Department required that MERC's future CCOSSs allocate income taxes on the basis of taxable income attributable to each customer class. The Department was able to verify that MERC's allocation of income taxes by class on the basis of taxable income that fully and only reflects the CCOSS results in an allocation identical to a rate base allocation under MERC's current circumstances. MERC used the same approach in its 2010 rate case. As approved by the Commission in that rate case, the Department and MERC agreed that in future rate cases, MERC allocate income taxes by class on the basis of taxable income that fully and only reflects the CCOSS.[463]

451. MERC supports its use of fully distributed embedded CCOSS. MERC's CCOSS fully and correctly demonstrates the embedded fixed costs of residential service. Moreover, calculating a CCOSS involves a degree of judgment and, therefore, there will not be one singularly correct CCOSS for a utility.[464]

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[461] Ex. 151 at 26-28 (J. Lindell Direct); Ex. 153 at 6-9 (J. Lindell Rebuttal); Ex. 154 at 12-15 (J. Lindell Surrebuttal).

[462] Ex. 208 at 4 (S. Ouanes Rebuttal).

[463] Ex. 30 at 36-41 (J. Hoffman Malueg Rebuttal).

[464] Ex. 29 at 5 (J. Hoffman Malueg Direct); Ex. 30 at 25, 44 (J. Hoffman Malueg Rebuttal); Evidentiary Hearing Transcript (May 13, 2014) at 70 (J. Hoffman Malueg) (Doc. ID No. 20145-99937-01).

452. MERC's CCOSS should be adopted in this proceeding, and used as a basis for revenue apportionment and rate design.

B. Revenue Apportionment

453. MERC's proposed revenue apportionment considered the following primary objectives:

- collect total revenues sufficient to allow the Company to recover its cost of operations for the test year, including a reasonable return on investment;
- reflect the cost of providing service to each customer class, as supported by the CCOSS, while giving consideration to non-cost factors where appropriate, e.g., value of service;
- provide overall revenue stability to the Company;
- encourage sound economic energy use;
- minimize cross-subsidization between rate classes;
- avoid large bill impacts or "rate shock;"
- limit the impact of the proposed rates on low-income customers; and
- provide flexibility on pricing and service conditions, which will allow the Company's natural gas services to be competitive with other energy sources.[465]

454. The CCOSS was the starting point for the apportionment of the retail revenue requirement among the rate classes. Other rate design goals were then considered, as noted above, such as maintaining competitive pricing for competitive services, and limiting large bill impacts or "rate shock." The Company's goal was to recover as closely as possible the costs imposed by each class, while avoiding unacceptably high billing impacts.[466]

455. MERC's proposed revenue apportionment was presented in a graphic format that compared current revenues from a customer class to proposed revenues and the revenue that would be justified by a full movement to the cost as indicated by the CCOSS.[467]

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[465] Ex. 40 at 6 (G. Walters Direct).

[466] Ex. 40 at 8, 28 (G. Walters Direct).

[467] Ex. 40 at 9-10 and Schedule (GJW-1), Schedule 3, Summary (including gas costs), and Schedule 5, Summary (not including gas costs) (G. Walters Direct).

456. The Department reviewed MERC's proposed revenue apportionment and recommended adoption of the Department's proposed revenue apportionment as detailed in Tables 2 and 3, and Attachment SLP-3 of the Direct Testimony of Susan Peirce.[468]

457. The Department recommended that if the Commission approves a lower revenue requirement than that requested by the Company, the remaining revenue requirement be apportioned proportionally to all classes, consistent with the approved apportionment of revenue responsibility.[469]

458. MERC generally agreed with the Department's proposed apportionment of revenue responsibility, but concluded that the SLV Customer Class and Flex customers should not change from proposed rates due to the revenue apportionment, except for MERC's updated proposal related to the CCRC. MERC pointed out that this is a very cost-sensitive customer class and any unintended increase could result in customer loss to MERC.[470]

459. MERC noted that it had accepted the Department's updated sales forecast, but the sales adjustments made by the Department fluctuate between customer classes. This discrepancy in sales increase makes it impossible for MERC to hold revenue apportionment at the class by PGA level as recommended by the Department and keep the distribution and customer charge rates for all residential customers the same. Therefore, MERC proposed to group customers together that have the same distribution rates for revenue apportionment purposes.[471]

460. The Department agreed with MERC's updated revenue apportionment with MERC's modification for the SLV and Flex customer classes.[472]

461. The revenue apportionment agreed to by MERC and the Department is reasonable and should be adopted in this proceeding. MERC's proposed revenue apportionment summarized in Mr. Walters' Rebuttal Testimony, and reflected in SLP-S-1 and SLP-S-2 to Ms. Peirce's Surrebuttal Testimony, should be used to determine the final rate design after the Commission has determined the final revenue requirement.[473]

C. Rates

462. The Department disagreed with one of MERC's proposed customer charges in this rate case, the residential customer charge. MERC agreed to the Department's recommend change. Thus, MERC and the Department have reached agreement regarding all rate

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[468] Ex. 203 at 10-11, 13 (S. Peirce Direct).

[469] Ex. 203 at 13 (S. Peirce Direct).

[470] Ex. 42 at 4 (G. Walters Rebuttal).

[471] Ex. 42 at 4-5 (G. Walters Rebuttal).

[472] Ex. 205 at 2-3 (S. Peirce Surrebuttal).

[473] Ex. 205 at 3-4 (S. Peirce Surrebuttal).

components. The OAG-AUD maintains that the customer charges for the Residential and Small Commercial and Industrial classes should not be increased.[474]

1. Residential Customer Charge

463. MERC's existing residential customer charge is $8.50 per month.[475] MERC initially proposed to increase the monthly residential customer charge to $11.00 per month.[476]

464. The Department recommended raising the residential customer charge to $9.50 per month. The Department reasoned that the increase to $9.50 would move the residential customer charge closer to cost without resulting in rate shock. The Department further reasoned that the increase is consistent with other increases in residential customer charges.[477]

465. MERC accepted the Department's recommendation that the residential customer charge be increased to $9.50.[478]

466. The OAG-AUD recommended retaining the existing residential customer charge.[479]

467. Because the customer charges are below the customer cost, it is necessary to recover the unrecovered customer costs through the distribution charge. As a result, customers with higher than average usage pay more than their proportional share of these costs. The proposed increase in the residential customer charge addresses this inconsistency.[480]

468. A higher customer charge will result in more level winter and summer bills, provides a more accurate price signal to customers by bringing their rates closer to the true cost of service, and provides incrementally more stable cash flow to the utility.[481]

469. An increase in the residential customer charge to $9.50 per month appropriately assigns costs to that class and avoids rate shock. The ALJ recommends that the Commission approve MERC's proposal to increase the residential customer charge to $9.50 per month.

2. Joint Service

470. Joint Service allows an interruptible customer to designate a portion of its interruptible service as firm service. Thus, Joint Service customers could have their service

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474 Ex. 150 at 36-47, 59-60 (V. Chavez Direct, adopted by J. Lindell); Ex. 154 at 15-20 (J. Lindell Surrebuttal).

475 Ex. 40 at 11 (G. Walters Direct).

476 Ex. 40 at 10 (G. Walters Direct); Ex. 42 at 6 (G. Walters Rebuttal).

477 Ex. 203 at 16-19 (S. Peirce Direct).

478 Ex. 42 at 7-8 (G. Walters Rebuttal).

479 Ex. 154 at 15 supporting the testimony of V. Chavez (J. Lindell Surrebuttal); Ex. 150 at 38 (V. Chavez Direct, adopted by J. Lindell).

480 Ex. 40 at 12-13, 17 (G. Walters Direct).

481 Ex. 40 at 13, 15 (G. Walters Direct).

curtailed down to the level of usage designated as firm. Joint service customers pay a per therm rate for daily firm capacity based on the amount of capacity designated as firm.[482]

471. In the November 27, 2013 Notice and Order for Hearing in this proceeding, the Commission requested that MERC provide supplemental testimony explaining how Joint Service customers are billed for service. On December 26, 2013, MERC filed supplemental testimony explaining how joint service customers are charged for their designated firm service.[483]

472. The Department determined that MERC's firm rate customers do not appear to be subsidizing the Company's Joint Rate customers and recommended that the Commission accept MERC's explanation on administering the Company's Joint Service.[484]

3. Customer Charges for Larger Customers

473. MERC proposed to increase the customer charges for its larger customers, including the Small Commercial and Industrial ("C&I"), Large Commercial and Industrial ("Large C&I"), Small Volume Interruptible ("SVI"), Large Volume Interruptible ("LVI"), and SLV customers. In addition, MERC proposed a monthly charge for the SLV Town Plant Transportation rate class, and to increase the administrative charge from $70.00 to $100.00 per metered account.[485]

474. The Department agreed with MERC's proposed changes.[486] The table below shows the customer charges, MERC's proposed customer charges, and the charges agreed upon by MERC and the Department.[487]

	Current Customer Charge	MERC Proposed Customer Charge	Charge Agreed to by MERC and Department
General Service Residential Consolidated Sales	$8.50	$11.00	$9.50
General Service Small Commercial & Industrial Consolidated Sales	$14.50	$18.00	$18.00
General Service Large Commercial & Industrial	$35.00	$45.00	$45.00

482 Ex. 203 at 20 (S. Peirce Direct).

483 Ex. 203 at 20-21 (S. Peirce Direct).

484 Ex. 203 at 21-22 (S. Peirce Direct).

485 Ex. 40 at 15-29 and Schedule (GJW-1) (G. Walters Direct).

486 Ex. 205 at 3 (S. Peirce Surrebuttal).

487 Ex. 40 at 7-8 (G. Walters Direct); Ex. 205 at 3 (Peirce Surrebuttal).

Consolidated Sales			
Small Volume Interruptible Consolidated Sales	$150.00	$165.00	$165.00
Large Volume Interruptible Consolidated Sales	$175.00	$185.00	$185.00
Super Large Volume Town Plant Transportation	$300.00	$350.00	$350.00

475. The OAG-AUD recommended no increase to the customer charge for the Small C&I class.[488] The OAG-AUD recommended that any increase in the residential class required revenues should be recovered through the variable per therm rate, rather than an increased customer charge.[489] The OAG-AUD also assumed that any increase to the residential or small C&I customer charge is unnecessary because MERC has full decoupling which assures collection of its fixed costs of providing service.[490]

476. In addition to increased customer charges for larger customers, MERC proposed to increase the Transportation Administration Fee from $70 to $110.[491]

477. This proposal was not addressed by any party, so MERC assumes agreement by all parties.[492]

478. The ALJ finds that MERC's proposed increase to the customer charges for larger customers, including its proposal to increase the transportation administration fee is supported by the CCOSS. The Commission should adopt the proposed customer charges, as agreed to by MERC and the Department.

V. Tariff Changes

479. MERC requests only that the rate tariff sheets and base cost of gas sheets be changed. MERC proposes no other tariff changes.[493]

480. The ALJ finds that MERC's request to change the Company's rate tariff sheets and base cost of gas sheets is appropriate and should be approved in this rate case.

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[488] Ex. 154 at 15 supporting the testimony of V. Chavez (J. Lindell Surrebuttal).

[489] Ex. 154 at 15-16 (J. Lindell Surrebuttal).

[490] Ex. 154 at 16 (J. Lindell Surrebuttal).

[491] Ex. 40 at 24 (G. Walters Direct).

[492] Ex. 42 at 8 (G. Walters Rebuttal).

[493] Ex. 40 at 32 (G. Walters Direct).

VI. REVENUE DECOUPLING

481. MERC does not request any changes to the methodology of how its pilot decoupling mechanism works. However, MERC does note that the sales and customer counts used in the decoupling calculation need to be consistent with the final sales and customer counts approved in this case.[494]

482. Contrary to the testimony of the OAG-AUD,[495] MERC does not have full decoupling for Residential and Small C&I customers. MERC's decoupling mechanism, which only applies to distribution revenues less the CCRC, is a use per customer calculation, and the decoupling mechanism includes a 10 percent symmetrical cap on distribution revenues.[496]

VII. OTHER COMMISSION REQUIREMENTS

A. Telemetry Installation

483. In the Commission's August 26, 2010 Order setting reporting requirements in Docket No. G-999/CI-09-409, the Commission required MERC to provide a status report on implementation of telemetering for the Company's small volume, large volume, and SLV customers, as well as the status of automated meter reading, if applicable, for the Company's other customers.

484. MERC has completed the installation of all the telemetering for its interruptible and transportation customers (i.e., small volume, large volume, and SLV). MERC does not intend to pursue the installation of automated meter reading at this time because the Company has determined that it is not currently economically feasible.[497]

B. Farm Tap Inspection Program

485. In Docket No. G011/M-91-989, the Commission required MERC to file in each general rate case a five-year report on the cumulative results of the Farm Tap Safety Inspection Program and any recommendations for future improvements. MERC stated that the Company is at the end of a five-year farm tap inspection plan, and included the inspection report in its initial filing in this proceeding.[498]

486. The South Dakota Farm tap customers were sold in May 2011, and are no longer customers of MERC. Therefore, these customers are no longer included in MERC's corporate structure and are not included in this filing.[499]

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[494] Ex. 16 at 4 (B. Nick Direct); Ex. 19 at 51 (S. DeMerritt Direct); Ex. 24 at 27 (S. DeMerritt Rebuttal).

[495] Ex. 154 at 1 adopting the testimony of Victor Chavez (J. Lindell Surrebuttal).

[496] Ex. 24 at 27 (S. DeMerritt Rebuttal).

[497] Ex. 40 at 33 (G. Walters Direct).

[498] Ex. 14 at 14-15 and Exhibit (DGK-4) (D. Kult Direct); Ex. 210 at 28-29 (M. Zajicek Direct).

[499] Ex. 19 at 29 (S. DeMerritt Direct).

487. MERC concluded that its farm tap inspection program continues to be an effective way to discover and repair leaks in the farm tap customers' lines.[500]

488. The Department recommended that MERC be required to continue the farm tap inspection program and submit in the Company's next rate case the most recent five-year farm tap inspection reports, together with a discussion of the results of the reports, and any recommendations for improvements to the farm tap safety inspection program.[501]

489. MERC agreed with the Department's recommendations.[502]

490. The ALJ finds that the Commission should approve MERC's five-year farm tap inspection report and the proposed continuation of the farm tap program.

VIII. FILING REQUIREMENTS FOR TRAVEL, ENTERTAINMENT AND OTHER EMPLOYEE EXPENSES

491. In 2010, Minn. Stat. § 216B.16 was amended to include subdivision 17, which specifies the filing requirements for travel, entertainment and other employee expenses.[503]

492. In its initial filing, MERC provided the information required by Minn. Stat. § 216B.16, subd. 17, including the travel, entertainment, related expenses and separately itemized expenses for MERC's board of directors and ten highest paid employees.[504]

493. Minn. Stat. § 216B.16, subd. 17(c), allows for the salary of one or more of the ten highest paid officers and employees, other than the five highest paid, to be treated as private data on individuals. Specifically, Minn. Stat. § 216B.16, subd. 17(c), provides:

> (c) Except as otherwise provided in this paragraph, data submitted to the commission under paragraph (a) are public data. The commission or an administrative law judge assigned to the case may treat the salary of one or more of the ten highest paid officers and employees, other than the five highest paid, as private data on individuals as defined in section 13.02, subdivision 12, or issue a protective order governing release of the salary, if the utility establishes that the competitive disadvantage to the utility that would result from release of the salary outweighs the public interest in access to the data. Access to the data by a government entity that is a party to the rate case must not be restricted.

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500 Ex. 14 at 15 (D. Kult Direct).

501 Ex. 210 at 30, 32 (M. Zajicek Direct); Ex. 211 at 4-5 (M. Zajicek Surrebuttal).

502 Ex. 15 at 6 (D. Kult Rebuttal).

503 Minnesota Laws, 2010, Chapter 328, Section 2.

504 Ex. 19 at 47 (S. DeMerritt Direct); Ex. 4 Initial Filing Volume 3: Informational Requirements, Document 14 at 1.

494. MERC requested that the salaries of the sixth through tenth highest paid employees be kept nonpublic for competitive reasons related to the compensation of MERC's employees. Publicly disclosing this information could give competitors an advantage in terms of hiring and retaining key employees. Additionally, it would be inappropriate to ignore the employees' right to keep this information private.[505]

495. The salaries of the sixth through tenth highest paid employees should be treated as private data as individuals, as contemplated by Minn. Stat. § 216B.16, subd. 17(c).

496. The Department recommended that MERC remove from the Company's General and Administrative expenses $7,770 for to travel and entertainment.[506]

497. MERC agreed with this recommendation.[507]

498. The OAG-AUD recommended a reduction of $569,450 for travel and entertainment expenses. In addition, the OAG-AUD recommended that dues totaling $63,245 for three organizations that it determined were lobbying organizations also be disallowed.[508]

499. The OAG-AUD argued that MERC provided unreadable information, did not include T&E expenses allocated to the Company by IBS and failed to provide a business purpose for the Company's expenses sufficient to support recovery. The OAG-AUD also argued that MERC failed to provide dues and expenses for memberships in organizations or clubs as required by the statute. In particular, the OAG-AUD argued that MERC sought recovery of dues and expenses for lobbying organizations, for which gas customers should not have to pay.[509]

500. MERC disagreed with the OAG-AUD's recommended T&E reduction which appears to be based on the OAG-AUD's opinion that MERC failed to meet the Minnesota statutory requirements for travel and entertainment expenses.[510] MERC believes it has met the statutory requirements and feels its travel and entertainment expenses are reasonable.[511]

501. In Rebuttal Testimony, the OAG-AUD made four recommendations for future MERC filings related to T&E expenses: 1) provide better descriptions for the business purposes of expenses, including the event or activity that the employee was attending or conducting; 2) include all T&E expenses, including T&E for employees who work for affiliates of MERC; 3) exclude all expenses incurred outside of Minnesota unless the description justifies an

505 Ex. 19 at 49-50 (S. DeMerritt Direct).

506 Ex. 215 at 23 (L. La Plante Direct).

507 Ex. 24 at 17-18 (S. DeMerritt Rebuttal).

508 Ex. 151 at 25-26 (J. Lindell Direct); Ex. 153 at 2-3 (J. Lindell Rebuttal); Ex. 154 at 9 (J. Lindell Surrebuttal).

509 Ex. 151 at 23-25 (J. Lindell Direct); Ex. 154 at 7-9 (J. Lindell Surrebuttal).

510 Ex. 24 at 26 (S. DeMerritt Rebuttal).

511 *See* Sections U and KK of the Proposed Findings; Evidentiary Hearing Transcript (May 13, 2014) at 25 (S. DeMerritt) (Doc. ID No. 20145-99937-01).

allocation to Minnesota; and 4) allocate only a portion of T&E expenses for items not specific to Minnesota such as for the Vertex T&E.[512]

502. MERC disagreed with the OAG-AUD's first recommendation. MERC found the term "better" to be subjective and determined that there is no reason to believe that any additional information above what was already provided would meet the needs of the OAG-AUD. MERC believes it met the requirements of Minnesota Statute § 216b.16, subd 17.[513]

503. MERC agreed to the OAG-AUD's second recommendation but emphasized that its agreement should in no way be construed as an admission of incompleteness in the current docket.[514]

504. MERC disagreed with the OAG-AUD's third recommendation. MERC incurs legitimate T&E expenses outside of Minnesota, and simply because these expenses do not occur within Minnesota state borders is no reason to deny recovery of these expenses. Some examples of these expenses include travel to Green Bay for MERC Board of Director meetings or training.[515]

505. MERC agreed with the OAG-AUD's fourth recommendation and specified that any costs not specific to Minnesota will be allocated to MERC based on the allocation factors discussed in MERC's Direct Testimony.[516]

506. The ALJ finds that, subject to the modification agreed to by MERC above, MERC's travel, entertainment and other employee expenses are reasonable and should be approved in this rate case.

507. Based on these Findings of Fact, the Administrative Law Judge makes the following conclusions:

IX. CONCLUSIONS

1. The Minnesota Public Utilities Commission and the ALJ have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. Chapter 216B and §14.50.

2. Any of the foregoing findings that is more appropriately deemed to be a conclusion is hereby adopted as a conclusion.

3. Use of the year ending on December 31, 2014 as the projected test year for determining MERC's revenue requirement is reasonable. MERC's projected test year rate base for the twelve-month period ending December 31, 2014, is approximately set at $199,192,236.

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[512] Ex. 153 at 4 (J. Lindell Rebuttal).

[513] Ex. 25 at 2-3 (S. DeMerritt Surrebuttal).

[514] Ex. 25 at 3 (S. DeMerritt Surrebuttal).

[515] Ex. 25 at 3-4 (S. DeMerritt Surrebuttal).

[516] Ex. 24 at 4 (S. DeMerritt Rebuttal).

MERC's test year operating revenues and expenses should be determined as set forth in Schedule 1 in to MERC's Issues Matrix filed June 6, 2014. The adjustments to revenues and expenses made by the Company throughout the proceeding result in a test year operating income for MERC of approximately $8,817,851. MERC's updated capital structure and cost of debt is reasonable, and should be utilized in the calculation of the rate of return.

4. MERC has demonstrated that its proposed ROE strikes an appropriate balance between the interests of shareholders and rate payers, and should be adopted in this matter.

5. With the adoption of the capital structure, cost of debt and cost of equity, the rate of return should be 8.0092 percent, as updated in Schedule (SSD-4) of Mr. DeMerritt's Rebuttal Testimony.

6. MERC's request for recovery of its 2014 approved CIP program budget is reasonable and should be adopted. The CCRC factor calculated at the end of this rate case should be based upon these amounts.

7. MERC will need to make an adjustment to the CIP tracker at the time of final rates. If MERC's CCRC of $0.02462 is approved in this proceeding, MERC will have under-collected CIP expense during the time frame that the Company's interim rates were in effect. MERC will then credit the CIP tracker balance (Account No. 182705) by $0.00030 ($0.02462 - $0.02432) x actual sales during the period interim rates were in effect, and debit the CIP Amortization account (Account No. 407710) for this same amount.

8. MERC will apply a one-time carrying charge to the unrecovered CIP balance related to Northshore Mining. For the carrying charge rate, MERC will use the Company's approved overall rate of return in effect during the period of under collection (July 2006 through December 2013). MERC will credit the CIP tracker for uncollected amounts (CCRC and CCRA) from July 2006 through December 2013, before Northshore's CIP exemption was effective January 1, 2014. MERC will also report this information in its final rates compliance filing in the present docket.

9. The record in this matter shows that MERC will experience a substantial revenue shortfall. MERC is entitled to recover this revenue shortfall through an adjustment of its natural gas rates. MERC's revenue deficiency is approximately $12,159,454.

10. MERC's proposed rate design should be adopted. This includes setting the monthly residential customer charge for both MERC-PNG and MERC-NMU at $9.50. It also includes increases in the customer charges for MERC's larger customers. The Small C&I charge will be increased to $18.00; Large C&I, SVI will increase to $45.00; LVI will increase to $165; and Super Large Volume customers will increase to $185.

11. Modifying MERC's natural gas rates in the manner described in the findings and conclusions above results in just and reasonable rates that are in the public interest.

12. Based on the foregoing findings and conclusions above, it is recommended that the Public Utilities Commission issue the following:

RECOMMENDATION

The ALJ recommends that the Commission issue an Order providing that:

1. MERC is entitled to increase gross annual revenues in accordance with the terms of the Report.

2. Within ten days of the service date of this Report, MERC shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirements and the rate design decisions based on the recommendations made herein.

3. MERC shall make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated: ___________________

ERIC L. LIPMAN
Administrative Law Judge

Reported: Transcript Prepared (one volume)
Shaddix & Associates

AFFIDAVIT OF SERVICE

STATE OF MINNESOTA)
) ss
COUNTY OF HENNEPIN)

Kristin M. Stastny hereby certifies that on the 24th day of June, 2014, on behalf of Minnesota Energy Resources Corporation (MERC) she electronically filed a true and correct copy of MERC's Proposed Findings of Fact, Conclusions, and Recommended Order on www.edockets.state.mn.us. Said documents were also served via U.S. mail and electronic service as designated on the attached service list.

/s/ Kristin M. Stastny
Kristin M. Stastny

Subscribed and sworn to before me
this 24th Day of June, 2014.

/s/ Alice Jaworski
Notary Public, State of Minnesota

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