OAH 65-2500-36528
MPUC G-004/GR-19-511

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Petition by
Great Plains Natural Gas Co.,
a Division of Montana-Dakota Utilities, Co.,
for Authority to Increase Natural Gas Rates
in Minnesota

TABLE OF CONTENTS

OAH 65-2500-36528
MPUC G-004/GR-19-511

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Petition by Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities, Co., for Authority to Increase Natural Gas Rates in Minnesota

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION

This matter came before Administrative Law Judge Ann O'Reilly for an evidentiary hearing on March 10, 2020, pursuant to a Notice and Order for Hearing issued by the Public Utilities Commission (Commission) on November 22, 2019. Public hearings were held in Marshall and Fergus Falls, Minnesota, on February 24, 2020. The period to submit written public comments expired on March 3, 2020.

Initial post-hearing briefs and proposed findings were filed by the parties on April 10, 2020. The hearing record closed on April 24, 2020, upon submission of the parties' reply briefs.

Brian M. Meloy, Stinson, LLP, appeared on behalf of Great Plains Natural Gas Co. (GP or Company).

Linda Jensen and Richard Dornfeld, Assistant Attorneys General, appeared on behalf of the Minnesota Department of Commerce's Division of Energy Resources (DOC-DER or Department).

Kristin Berkland and Peter Scholtz, Assistant Attorneys General, appeared on behalf of the Minnesota Office of the Attorney General, Residential Utilities and Antitrust Division (OAG).

Jorge Alonso, staff financial analyst, participated as a member of the Commission's staff.

STATEMENT OF THE ISSUES

In its Notice and Order for Hearing dated November 22, 2019, the Commission directed the parties and Administrative Law Judge to develop a full evidentiary record addressing the following issues:

1. The standard rate case issues, including whether the:

   (a) test year revenue increase sought by GP is just and reasonable or whether it will result in unreasonable and excessive earnings by the Company;

   (b) revenue requirements are reasonable and just;

   (c) rate design proposed by GP is just and reasonable; and,

   (d) proposed capital structure and return on equity is just and reasonable?

2. Whether GP's request to continue its Revenue Decoupling Mechanism (RDM) on a permanent basis should be approved and whether:

   (a) the pilot program should be extended beyond 2020 and, if so, for how long;

   (b) the proposed margin-sharing mechanism should be incorporated into the RDM; and,

   (c) a minimum energy savings level should be required in order to implement a surcharge;

3. What will be the impact of suspending the Gas Utility Infrastructure Cost (GUIC) rider and whether GP intends to continue use of the GUIC after the rate case;

4. Whether GP's redemption of preferred stock is reasonable and just;

5. Whether GP's sales forecast is accurate; and,

6. Whether GP's proposed change to the Conservation Cost Recovery Adjustment (CCRA) Factor, from the currently-approved CCRA Factor amount of (.0337) to the proposed Factor of (.0599), should be allowed in this general rate case or whether it should be addressed in a Conservation Improvement Program Tracker/DSM.[1]

---

[1] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 22, 2019) (eDocket No. 201911-157756-01).

SUMMARY OF RECOMMENDATION

In its Notice and Order for Hearing, the Commission instructed the parties and the Administrative Law Judge to develop a record and address specific issues.

With respect to the standard rate case issues, the Administrative Law Judge finds that the hearing record demonstrates that GP will experience a revenue shortfall and that the Company is entitled to recover this shortfall through an adjustment of its natural gas rates. The capital structure, costs of debt, and return on equity reflected in the Findings below are reasonable and should be used in determining an overall rate of return. Modifying GP's natural gas rates in the manner described in these Findings and Conclusions below, including those related to rate design, will result in just and reasonable rates that serve the public interest. In addition, providing for recovery of the expenses described in the Findings and Conclusions below is reasonable, appropriate, and supported by the hearing record.

With respect to GP's Revenue Decoupling Mechanism (RDM), the Administrative Law Judge recommends that the Commission allow the RDM to continue through 2021. After reviewing the Company's 2019 and 2020 CIP results, the Commission should decide whether to allow the RDM to continue. The Judge further recommends that the Commission: (1) approve the incorporation of GP's proposed margin sharing mechanism into the RDM; (2) require the Company to make an annual compliance filing; and (3) require that the revenue sharing mechanism be reviewed in the Company's next rate case or within five years from the Commission's order, whichever occurs first.

The Judge recommends that a minimum savings threshold not be imposed at this time.

With respect to the Gas Utility Infrastructure Cost (GUIC) rider, GP agreed to roll its rider revenue requirements into its rate case at the beginning of its test year. The Company stated plans to continue to utilize the GUIC rider for future recovery of GUIC-eligible projects beginning in 2021.

The Administrative Law Judge recommends that GP's sales forecast for the test year be accepted as reasonable.

Finally, the Judge recommends that the Company's proposed Conservation Improvement Program (CIP) expense of $566,621 be used as the basis for its Conservation Cost Recovery Adjustment (CCRA) rate and that any changes to the CCRA factor should be determined in the Company's next annual CIP tracker and financial incentive proceeding, rather than in the instant rate case.

FINDINGS OF FACT

I. INTRODUCTION

A. The Parties

1. GP is a division of Montana-Dakota Utilities Company (MDU).[2] MDU is a subsidiary of MDU Resources Group, Inc., an investor-owned company headquartered in Bismarck, North Dakota.[3] GP has a general office in Fergus Falls, Minnesota, and a district office in Marshall, Minnesota.[4] The Company operates as both a local distribution company and a transporter of natural gas to industrial, commercial, and residential customers in 18 Minnesota communities.[5]

2. The DOC-DER staff reviews the testimony and schedules filed by the company and other parties to assure their accuracy and completeness, and files testimony and argument addressing the reasonableness of the elements of the rate request.

3. The OAG advocates on behalf of residential and small business customers in proceedings before the Commission. The OAG staff reviews the testimony and schedules filed by the company and other parties, and files testimony and argument intended to protect the interests of the customers it represents.

B. Company Background

4. GP provides natural gas to approximately 22,038 customers in nine Minnesota communities, operating approximately 470 miles of distribution mains, and providing approximately 23,096 service connections.[6] The Company's customer base is 85 percent residential and 15 percent commercial and industrial.[7]

5. The residential general service and small interruptible customers use natural gas primarily for space and water heating.[8] The large commercial and industrial customers are primarily associated with agriculture and ethanol production.[9]

6. The annual natural gas delivery to GP's Minnesota customers is 8,488,170 Dk.[10] Approximately 34 percent of this amount is firm deliveries and the remaining 66 percent represents interruptible service deliveries.[11]

---

[2] Marshall Public Hearing Transcript (Tr.) at 10-11 (Feb. 24, 2020) (eDocket No. 20202-160799-01).
[3] *Id.*
[4] *Id*. at 11.
[5] *Id*.
[6] Exhibit (Ex.) GP-10 at 3 (Kivisto Direct).
[7] *Id.*
[8] *Id*. at 4.
[9] *Id*.
[10] *Id*.
[11] *Id*.

7. As of December 31, 2018, GP had 31 full- and part-time employees in Minnesota.[12] The company has operation centers in Fergus Falls and Marshall, Minnesota, which are supported by the regional operations center in Bismarck, North Dakota.[13]

8. The company's last rate case was filed on September 30, 2015 (2015 Rate Case).[14] The resulting rate increase was $1.14 million, representing a 5.2 percent overall annual increase, effective January 1, 2017.[15]

9. After the 2015 Rate Case, GP reduced its distribution rates to produce an annual decrease of $395,206, effective May 1, 2019.[16] This reduction was in response to the Commission's Order issued in its "Investigation into the Effects on Electric and Natural Gas Utility Rates and Services of the 2017 Federal Tax Act."[17]

C. The Application

10. On September 27, 2019, GP filed an application with the Commission requesting authority to increase its natural gas rates in Minnesota, including a proposed interim rates petition.[18] Along with its application, the Company filed the direct testimony of its witnesses.[19]

11. In its application, the Company requests a natural gas rate increase of $3,639,918, or an increase of 15.2 percent annually.[20] The Company is also requesting that the Gas Utility Infrastructure Cost (GUIC) rider revenue requirement from its last rate proceeding be moved into base retail rates beginning on January 1, 2020.[21]

12. The combined impact to customers will be a "new" rate increase of $2,860,839, representing a 12 percent increase in revenues.[22] This proposed rate increase seeks an overall rate of return of 7.46 percent, inclusive of a return on equity (ROE) of 10.20 percent.[23]

---

[12] *Id*. at 9.
[13] *Id*.
[14] *Id*. at 5 (citing *In the Matter of the Petition of Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota,* MPUC Docket No. G004/GR-15-879, FINDINGS OF FACT, CONCLUSIONS, AND ORDER (Sept. 6, 2016)).
[15] *Id*.
[16] *Id*. at 6.
[17] *Id*.
[18] *See* EXS. GP-1, GP-2, GP-3, GP-34 (Application and Initial Filings).
[19] Ex. GP-10 (Kivisto Direct); Ex. GP-12 (Nygard Direct); Exs. GP-14, GP-15 (Bulkley Direct and Workpapers); Ex. GP-18 (Shoemake Direct); Ex. GP-21 (Jacobson Direct); Ex. GP-25 (Hatzenbuhler Direct); Ex. GP-28 (Fischer Direct); Ex. GP-31 (Bosch Direct).
[20] Ex. GP-25 at 3 (Hatzenbuhler Direct).
[21] *Id*.
[22] *Id*.; Ex. GP-10 at 5 (Kivisto Direct).
[23] Ex. GP-10 at 12 (Kivisto Direct).

13. GP's proposed rate increase is based on a test year comprised of actual financial information from calendar year 2018, adjusted for known and measurable changes through year-end 2019, and projected through December 31, 2020.[24]

14. The impact of the proposed rate change by customer class is as follows:[25]

Customer Class	% Increase
Residential	15.7
Firm General	12.5
Interruptible Grain Drying	12.2
Small Interruptible	3.3
Large Interruptible	3.7
Overall	12.0

15. As these numbers demonstrate, the customer class receiving the highest rate increase under the proposed rate structure is the residential class, with a 15.7 percent increase.[26] The Company states that a typical residential customer using 81 dk annually will see an increase of $7.05 per month, or $84.60 per year, over current rates.[27]

16. GP is also requesting that the Revenue Decoupling Mechanism (RDM), which was implemented on a pilot basis in its 2015 Rate Case, be made permanent.[28] The Company seeks to introduce a margin sharing mechanism as part of the RDM.[29]

17. Finally, GP sought, and was granted by the Commission, an interim rate increase in the amount of $2,600,907 (an approximate 11% increase), effective January 1, 2020.[30] This rate increase is pending final Commission approval as part of this proceeding.

18. The primary reason GP asserts for needing a rate increase is the capital investments the company has made in distribution facilities in the Minnesota system to improve system safety and reliability.[31] These investments are based upon the company's Distribution Integrity Management Program (DIMP), which identified three top risks: (1) excavation damage to PVC pipe; (3) material failure related to PVC pipe; and (3) corrosion to vintage steel systems.[32] The Company started a structured replacement program in 2013 that focused on replacement of PVC pipe (distribution

[24] *Id*. at 5.
[25] *Id*. at 12.
[26] *Id*.
[27] *Id*.
[28] *Id*. at 12-13.
[29] *Id*.
[30] *Id*. at 14-15.
[31] *Id*. at 6.
[32] *Id*. at 7-8.

mains and services) throughout the system.[33] By the end of 2019, GP had replaced PVC facilities in five Minnesota communities.[34] A replacement project in one additional Minnesota community (Montevideo) will continue into 2020.[35]

19. The Company is also replacing approximately 6,000 feet of vintage steel pipe and 50 services in conjunction with the city of Montevideo.[36] According to GP, by the end of 2018, approximately 45 percent of the PVC mains and 55 percent of the PVC services were replaced.[37]

20. Since its 2015 Rate Case, the Company argues that gross plant investments have increased approximately 42 percent.[38] The plant investment expenses projected for 2020 is $67.3 million.[39] Nearly 70 percent of these costs relate to its distribution system.[40]

21. GP asserts that it has made approximately $19.9 million in infrastructure improvements investments since its last rate case, including $12.6 million in distribution line replacements and $3.5 million in pipeline replacements and re-routes near Fergus Falls.[41] In addition to these facility investments, the Company claims an increase in depreciation and property tax expenses.[42]

II. PROCEDURAL BACKGROUND

22. On October 1, 2020, the Commission issued a notice requesting comments as to whether GP's application should be accepted as substantially complete and whether the matter should be referred to the Office of Administrative Hearings for a contested case proceeding.[43] The DOC-DER[44] and the OAG submitted comments in response to the Commission's notice.[45] GP filed a reply to those comments.[46] No public comments were received.

23. In response to the OAG's comments, GP revised its interim rate request set forth in the application.[47] In its reply comments, the Company requested that the

---

[33] *Id*. at 8.
[34] *Id*.
[35] *Id*.
[36] *Id*. at 8-9.
[37] *Id*. at 9.
[38] *Id*.
[39] *Id*.
[40] *Id*.
[41] Marshall Public Hearing Tr. at 13-14 (Feb. 24, 2020) (eDocket No. 20202-160799-01).
[42] *Id*.
[43] NOTICE OF COMMENT PERIOD ON COMPLETENESS AND PROCEDURES (Oct. 1, 2019) (eDocket No. 201910-156227-01).
[44] Comments from DOC-DER (Oct. 3, 2019) (eDocket No.201910-156295-01).
[45] Comments from OAG (Oct. 7, 2019) (eDocket No. 201910-156396-01).
[46] Ex. GP-4 (GP Reply Comments) (Oct. 14, 2019) (eDocket No. 201910-156539-01).
[47] *Id*.

Commission approve an interim net rate increase of $2.6 million, or 10.93 percent, representing an annual interim rate revenue deficiency of $3,366,855, effective January 1, 2020.[48]

24. On November 15, 2019, GP submitted a compliance filing providing monthly customers and volumes through October 31, 2019. This filing was in compliance with the Commission's March 20, 2019 Order in Docket No. G-004/GR-15-879.[49]

25. On November 22, 2019, the Commission issued an Order Setting Interim Rates, which approved an annual interim rate revenue deficiency of $3,366,855, as requested by GP, and an implementation date of January 1, 2020.[50] The Commission also approved the Company's proposed interim cost of capital and its request to collect the interim rate increase in a uniform percentage added to the base service and/or delivery charge for all customers.[51] The Commission allowed GP to recover foregone interim revenue from its market-based rate customers, but denied such recovery from all other customers.[52] The Commission ordered the Company to keep and provide certain records to the Commission, including rate tariff sheets and supporting documentation, the rate increase notice to customers, and records necessary to calculate a potential refund.[53] Finally, the Commission ordered GP to maintain records of its Conservation Improvement Program (CIP) costs and collections during the interim period to calculate recoveries dedicated to CIP.[54]

26. The second order issued by the Commission on November 22, 2019, was the Order Accepting Filing, Suspending Rates, and Extending Timelines.[55] The order: (1) accepted the application as proper in form and substantially complete; (2) suspended the proposed final rates until final determination by the Commission; and (3) extended the deadline to complete this case under Minn. Stat. § 216B.15, subd. 2(f) (2018), to August 26, 2020.[56]

27. The third order issued on November 22, 2019, was the Notice and Order for Hearing, which referred this matter to the Office of Administrative Hearings for a contested case proceeding.[57] The order delineated the issues for hearing, and required that public hearings be held in locations within GP's service area.[58] The order also directed the Administrative Law Judge to complete her recommendation by May 26,

---

[48] *Id*. at Attachment A.
[49] Ex. GP-5 (Compliance Filing – Oct. 2019 Monthly Customers and Volumes).
[50] ORDER SETTING INTERIM RATES (Nov. 22, 2019) (eDocket No. 201911-157757-01).
[51] *Id*.
[52] *Id*.
[53] *Id*
[54] *Id*.
[55] ORDER ACCEPTING FILING, SUSPENDING RATES, AND EXTENDING TIMELINES (Nov. 22, 2019) (eDocket No. 201911-157755-02).
[56] *Id*.
[57] NOTICE AND ORDER FOR HEARING (Nov. 22, 2019) (eDocket No. 201911-157756-01).
[58] *Id*.

2020.[59] The Notice and Order for Hearing identified GP, the DOC-DER, and the OAG as the only parties to this proceeding.[60]

28. On December 2, 2019, the Company submitted a compliance filing in conformity with the Commission's Order Setting Interim Rates.[61] That same date, the GP also submitted a compliance filing setting forth the adjusted base cost of gas.[62]

29. On December 3, 2019, the Commission issued an Approval of Interim Rates to Customers Notice and a Notice to Counties and Municipalities of the rate case.[63]

30. GP submitted a Compliance Report on December 12, 2019, providing monthly customer and volume numbers through November 30, 2019.[64]

31. The first prehearing conference in this matter was held on December 18, 2019, at the Commission's office in Saint Paul.[65] At the prehearing conference, the Commission and the parties extended the date for the Administrative Law Judge's report to June 30, 2020.[66]

32. On January 6, 2020, the Administrative Law Judge issued the First Prehearing Order setting forth procedures and a schedule for this proceeding.[67] The First Prehearing Order established a deadline to intervene on January 10, 2020.[68] The order was amended on January 13, 2020, to make various corrections and to establish a deadline for public comments (March 3, 2020).[69]

33. On January 10, 2020, the OAG filed a Petition to Intervene.[70] There were no objections to the petition, and no other parties sought to intervene in this case.[71]

34. In conformity with the Amended First Prehearing Order, the DOC-DER and OAG filed the direct testimony of their witnesses on January 16, 2020.[72]

---

[59] *Id*.
[60] NOTICE AND ORDER FOR HEARING (Nov. 22, 2019) (eDocket No. 201911-157756-01).
[61] Compliance Filing – Interim Rates (Dec. 2, 2019) (eDocket No. 201912-157977-01).
[62] Ex. GP-8 (Compliance Filing – Base Cost of Gas Update).
[63] Approval of Interim Rates Customer Notice and a Notice to Counties and Municipalities (Dec. 3, 2019) (eDocket No. 201912-157984-01).
[64] Ex. GP-6 (Compliance Filing- Nov. 2019 Monthly Customers and Volumes).
[65] PREHEARING TR. (Dec. 18, 2019) (eDocket No. 201912-158667-01).
[66] *Id.*
[67] FIRST PREHEARING ORDER (Jan. 6, 2020) (eDocket No. 20201-158855-01).
[68] *Id*.
[69] AMENDED FIRST PREHEARING ORDER (Jan. 13, 2020) (eDocket No. 20201-159061-01).
[70] OAG PETITION TO INTERVENE (Jan. 10, 2020) (eDocket No. 20201-159015-01).
[71] SECOND PREHEARING ORDER AND ORDER GRANTING PETITION TO INTERVENE (Jan. 24, 2020) (eDocket No. 20201-159581-01).
[72] Ex. OAG-1 (Lebens Direct); Ex. DER-1 (Addonizio Direct); Ex. DER-2 (Shah Direct); Ex. DER-3 (Ouanes Direct); Ex. DER-4, DER-4TS (Zajicek Direct and trade secret); Ex. DER-5 (Davis Direct); Ex. DER-6 (Byrnes Direct); Ex. DER-7 (Lusti Direct).

35. GP submitted a Compliance Report on January 21, 2020, providing monthly customer and volume numbers through December 31, 2019.[73]

36. A Second Prehearing Order and Order Granting Petition to Intervene was issued on January 24, 2020.[74] The order granted OAG's Petition to Intervene and made minor revisions to the Amended First Prehearing Order.[75] None of the deadlines were changed.[76]

37. On February 6, 2020, the Company filed a copy of the interim rate bill insert for Commission approval in conformity with the Order Setting Interim Rates.[77]

38. GP and the DOC-DER filed rebuttal testimony on February 11, 2020.[78]

39. On February 13, 2020, the Company submitted a compliance filing updating the base cost of gas.[79]

40. The Commission issued a Notice of Public Hearing on February 20, 2020.[80]

41. On February 21, 2020, GP submitted a Compliance Report providing monthly customer and volume numbers through January 31, 2020.[81]

42. Public hearings were held on February 24, 2020, in Marshall and Fergus Falls.[82]

43. The public comment period closed on March 3, 2020, and no written public comments were received.

44. On March 3, 2020, the DOC-DER and OAG filed Surrebuttal Testimony.[83]

---

[73] Ex. GP-7 (Compliance Filing – Dec. 2019 Monthly Customers and Volumes).
[74] SECOND PREHEARING ORDER AND ORDER GRANTING PETITION TO INTERVENE (Jan. 24, 2020) (eDocket No. 20201-159581-01).
[75] *Id*.
[76] *Id*.
[77] Compliance Filing – Interim Rates Bill Insert (Feb. 6, 2020) (eDocket No. 20202-160169-01).
[78] Ex. GP-16 (Bulkley Rebuttal); Ex. GP-19 (Shoemake Rebuttal); Ex. GP-23 (Jacobson Rebuttal); Ex. GP-26 (Hatzenbuhler Rebuttal); Ex. GP-29 (Fischer Rebuttal); Ex. GP-32 (Bosch Rebuttal); Ex. DER-8 (Zajicek Rebuttal).
[79] Ex. GP-8 (Compliance Filing – Base Cost of Gas Update).
[80] PUBLIC HEARING NOTICE (Feb. 20, 2020) (eDocket No. 20202-160578-01).
[81] Compliance Filing – January Monthly Customers and Volumes (Feb. 21, 2020) (eDocket No. 20202-160591-01).
[82] Public Hearing Transcripts (Feb. 24, 2020) (eDocket No. 20202-160799-01).
[83] Ex. DER-9 (Addonizio Surrebuttal); Ex. DER-10 (Shah Surrebuttal); Ex. DER-11 (Ouanes Surrebuttal); DER-12 (Zajicek Surrebuttal); DER-14 (Byrne Surrebuttal); Ex. DER-15 (Lusti Surrebuttal); Ex. OAG-2 (Lebens Surrebuttal). The DOC-DER filed a corrected version of Angela Byrne's Surrebuttal Testimony on March 6, 2020. *See* eDocket Nos. 20203-161038-01, 20203-161038-02, 20203-161038-03.

45. A mediation session was held on March 4, 2020, at the Commission offices in St. Paul, Minnesota. The parties advised the Administrative Law Judge of the issues that were resolved among the parties.

46. On March 6, 2020, the parties filed their proposed witness and exhibit lists.[84] In addition, the parties exchanged their witness summaries to be offered at the hearing.[85]

47. On March 9, 2020, GP filed a Motion to Include Limited New Information Into the Hearing Record.[86] This motion requested to include new information in Ann Bulkley's witness summary that was not previously included in her direct or rebuttal testimony.[87] This information related to recent volatility in the markets arising after the filing of her rebuttal testimony, as well as a 2019 Report from South Jersey Industries addressing impairments that was released on February 26, 2020, after the filing of Ms. Buckley's rebuttal testimony.[88]

48. That same day, the DOC-DER filed a letter requesting permission to allow their witness, Craig Addonizio, to address the new matters included in Ms. Bulkley's witness summary.[89]

49. In addition, on March 10, 2020, just prior to the start of the evidentiary hearing, the DOC-DER filed a Motion to Exclude the new information contained in Ms. Bulkley's witness summary.[90]

50. An evidentiary hearing was held on March 10, 2020, at the Commission's office in Saint Paul.[91] At the start of the hearing, the Administrative Law Judge heard the parties' arguments regarding the new information contained in Ms. Bulkley's witness summary.[92] The Judge permitted Ms. Buckley's witness summary to be admitted into the record but allowed Mr. Addonizio to file a three-page response by March 13, 2020, which would be included in the hearing record.[93]

---

[84] GP Witness and Exhibit Lists (Mar. 6, 2020) (eDocket No. 20203-161026-01); DOC-DER Witness and Exhibit Lists (Mar. 6, 2020) (eDocket No. 20203-161045-01); OAG Witness and Exhibit Lists (Mar. 6, 2020) (eDocket No. 20203-161041-01).
[85] DOC-DER Witness Summary Statements (Mar. 6, 2020) (eDocket No. 20203-161040-01). The DOC-DER was the only party to file its witness summaries in eDockets prior to the hearing. GP and the OAG provided a copy of their witness summaries to the Administrative Law Judge and the other parties via email on March 6, 2020, but did not file them in eDockets.
[86] Motion to Include Limited New Information Into the Hearing Record (Mar. 9, 2020) (eDocket No. 20203-161054-01).
[87] *Id.*
[88] *Id.*
[89] Letter from Richard Dornfeld to Administrative Law Judge Ann O'Reilly (Mar. 6, 2020) (eDocket Nos. 20203-161083-01 and 20203-161084-01).
[90] Motion to Exclude (Mar. 10, 2020) (eDocket No. 20203-161082-01).
[91] EVIDENTIARY HEARING TRANSCRIPT (Mar. 25, 2020) (eDocket No. 20203-161440-01).
[92] *Id.*
[93] *Id.*

51. On March 20, 2020, GP submitted its monthly customer and volumes report for February 2020.[94]

52. The parties filed a joint Issues Matrix on March 30, 2020.[95]

53. On April 10, 2020, the parties submitted Initial Briefs and Proposed Findings of Stipulated Facts.[96]

54. The parties filed Reply Briefs and Proposed Findings on Contested Facts on April 24, 2020.[97]

55. The hearing record closed on April 24, 2020.

III. PUBLIC HEARING AND COMMENTS

A. Public Hearings

56. In its Notice and Order for Hearing, the Commission directed the Administrative Law Judge to hold public hearings in locations within the Company's service area.[98] The Order also directed GP to provide notices of the evidentiary and public hearings at least 10 days prior to the hearings: (1) to each customer in the form of a bill insert; (2) to all municipalities, counties, and local governing bodies in the area affected and to all parties in the Company's last two rate cases; and (3) in display advertisements in legal newspapers of affected counties and other newspapers of general circulation within the Company's service area.[99] The Company was also required to obtain Commission approval of the notices prior to publication or service.[100]

57. The Commission issued a Notice of Public Hearing on February 20, 2020.[101] This notice advised of the public hearings in Marshall and Fergus Falls, Minnesota on February 24, 2020; the public comment deadline of March 3, 2020; the evidentiary hearing on March 20, 2020; and the current and proposed gas rates for each customer class.[102]

---

[94] Compliance Filing - February Monthly Customers and Volumes (Mar. 20, 2020) (eDocket No. 20203-161368-01).
[95] Joint Issues Matrix (Mar. 30, 2020) (eDocket No. 20203-161573-02).
[96] GP Initial Brief (Br.) (Apr. 10, 2020) (eDocket No. 20204-162024-02); DOC-DER Initial Br. (Apr. 10, 2020) (eDocket No. 20204-162019-01); OAG Initial Br. (Apr. 10, 2020) (eDocket No. 20204-162021-01).
[97] GP Reply Br. (Apr. 24, 2020) (eDocket No. 20204-162440-02); DOC-DER Reply Br. (Apr. 24, 2020) (eDocket No. 20204-162437-01); OAG Reply Br. (Apr. 24, 2020) (eDocket No. 20204-162453-02).
[98] NOTICE AND ORDER FOR HEARING (Nov. 22, 2019) (eDocket No. 201911-157756-01).
[99] *Id.*
[100] *Id.*
[101] PUBLIC HEARING NOTICE (Feb. 20, 2020) (eDocket No. 20202-160578-01).
[102] *Id.*

58. A Rate Increase Notice was included with GP customer bills starting January 27, 2020, and was published in the following newspapers prior to the February 24, 2020, public hearings:[103]

Cottonwood Tri-County News
Crookston Times
Dawson Sentinel
Fergus Falls Daily Journal
Frazee Vargas Forum
Granite Falls Advocate Tribune
Marshall Independent
Montevideo American-News
Pelican Rapids Press
Redwood Falls Redwood Gazette
Renville County Register
Wahpeton Breckenridge Daily News

59. While the Company received approval of the Interim Rate Increase Notice insert,[104] there is nothing in the record to establish that GP received approval of the Rate Increase Notice.

60. Notwithstanding, a review of the Rate Increase Notice establishes that it accurately advised the public of: (1) the dates, times, and locations of the public hearings and the evidentiary hearing; (2) the opportunity to submit written comment and the deadline for submission of such comments; (3) the fact that GP is proposing a 12 percent increase ($2,860,839 per year), which would mean an increase of approximately $7.05 to an average retail customer's monthly bill; and (4) a chart showing the proposed rate increases for each customer class based upon average monthly usage.[105]

61. Two public hearings were held on February 24, 2020: one in Marshall and the other in Fergus Falls, Minnesota.[106]

1. Marshall Public Hearing

62. The first public hearing was held on February 24, 2020, at 11:00 a.m. at the Lyon County Library in Marshall, Minnesota.[107] Travis Jacobson and Jordan Hatzenbuhler appeared on behalf of GP; Susan Medhaug appeared for the DOC-DER;

[103] Copy of Public Hearing Notice Bill Insert (Mar. 3, 2020) (eDocket No. 20203-160930-01).
[104] Approval of Interim Rates Customer Notice and Notice to Counties and Municipalities (Dec. 3, 2019) (eDocket No. 201912-157984-01).
[105] Rate Increase Notice (Mar. 3, 2020) (eDocket No. 20203-160930-01).
[106] Public Hearing Transcripts (Feb. 24, 2020) (eDocket No. 20202-160802-01).
[107] Marshall 11:00 a.m. Public Hearing Tr. (Feb. 24, 2020) (eDocket No. 20202-160802-01).

Kristin Berkland appeared for the OAG; and Jorge Alonso appeared on behalf of the Commission.[108]

63. The Administrative Law Judge convened the hearing at 11:00 a.m.[109] The Company made a presentation and statements were read by both the DOC-DER and the OAG.[110]

64. Russ LaBat was the only member of the public who attended the public hearing.[111] There were no impediments to public participation, such as bad weather or facility issues. Mr. LaBat questioned the Company about whether the 12 percent increase would mean a new 12 percent increase each year (meaning, each year the Company would receive another 12 percent increase).[112] The Company explained that the 12 percent increase was over current rates and would not involve a 12 percent increase each year.[113]

65. Mr. LaBat stated that he understood the Company may be entitled to some increase, but that a 12 percent was excessive.[114] He expressed concern about how this increase could negatively impact residential customers, particularly the elderly who live on fixed incomes.[115]

66. After Mr. LaBat's comments, the meeting adjourned at 11:37 a.m.[116] A sign was posted at the entrance of the library advising members of the public how they could submit written comments until March 3, 2020.[117]

2. Fergus Falls Public Hearing

67. The second public hearing was held on February 24, 2020, at 6:00 p.m. at the National Guard Armory in Fergus Falls, Minnesota.[118] Travis Jacobson and Jordan Hatzenbuhler appeared on behalf of GP; Susan Medhaug appeared for the DOC-DER; Peter Scholtz appeared for the OAG; and Jorge Alonso appeared on behalf of the Commission.

68. No members of the public appeared.[119] The Administrative Law Judge held the meeting open until 6:15 p.m. and adjourned the meeting.[120] A sign was posted

---

108 *Id*. at 5.
109 *Id*. at 3.
110 *Id*. 10-18.
111 *Id*. at 21-24.
112 *Id*. at 21-22.
113 *Id*.
114 *Id*. at 21-24.
115 *Id*.
116 *Id*. at 25.
117 *Id*. at 24.
118 *Id*. at 25-26.
119 *Id*.
120 *Id*.

at the entrance of the Armory advising members of the public how they could submit written comments until March 3, 2020.[121]

B. Written Comments

69. There were no written comments submitted.

IV. LEGAL STANDARDS

70. The Commission must set rates that are just and reasonable, balancing the interests of the utility and its customers.[122] A reasonable rate enables a utility not only to recover its operating expenses, depreciation, and taxes, but also allows it to compete for funds in the capital market. Minnesota law recognizes this principle when it defines a fair rate of return as the rate which, when multiplied by the rate base, will give a utility a reasonable return on its total investment.[123]

71. The utility seeking an increase in its rates has the burden of proving by a preponderance of the evidence that its proposed change will result in just and reasonable rates.[124] This standard applies both in a traditional rate case and when a utility has proposed a multi-year rate plan.[125]

72. In the context of a rate proceeding, the "preponderance of the evidence" is defined as "whether the evidence submitted, . . . if true, justifies the conclusion sought by the petitioning utility when considered together with the Commission's statutory duty to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates."[126] Any doubt as to reasonableness of the proposed rates is to be resolved in favor of the consumer.[127]

73. The Commission acts in both a quasi-judicial and quasi-legislative capacity in setting rates. On purely factual issues, the Commission acts in its quasi-judicial capacity. On issues involving policy judgment, the Commission acts in its quasi-legislative capacity, balancing competing interests and policy goals to arrive at the resolution most consistent with the broad public interest.[128]

V. REVENUE REQUIREMENT - INTRODUCTION

74. The revenue requirement portion of a rate case seeks to determine how much additional revenue is needed to meet the utility's required operating income,

---

[121] *Id*. at 26.
[122] Minn. Stat. § 216B.03 (2018).
[123] Minn. Stat. § 216B.16, subd. 6 (2018).
[124] *Id*. at subds. 4, 19(a) (2018).
[125] *Id.*
[126] *In re Northern States Power Co.,* 416 N.W.2d 719, 722 (Minn. 1987).
[127] Minn. Stat. § 216B.03.
[128] *St. Paul Chamber of Commerce v. Minn. Pub. Utilities Comm'n*, 251 N.W.2d 350, 356-57 (Minn. 1977).

based upon a "test year" of operations. The required operating income is derived from determining the amount of investments in the rate base that have been made by a utility's shareholders and then multiplying the approved rate base times the rate of return that is determined to be appropriate for GP.

75. After determining the required operating income, GP's test year expenses and revenues are evaluated to determine the current operating income for the test year. 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.

76. GP's proposed rate increase is based on a test year comprised of actual financial information from calendar year 2018, adjusted for known and measurable changes through year-end 2019, and projected through December 31, 2020.[129] Accordingly, the "test year" in this proceeding is 2020.

77. Using this test year, the Company predicts a revenue deficiency of $3,639,839, based on projected 2020 operating income and rate base, with an overall rate of return of 7.460 percent.[130]

78. GP has proposed to include, in base retail rates, the costs associated with the assets currently being recovered in its GUIC Adjustment from its 2015 Rate Case.[131] The Company has also requested that the Commission approve the 2019 projects submitted in Docket No. M-19-273 and allow the Company to suspend the GUIC rate upon the implementation of interim rates, because the 2019 projects have been included in the rate base of this case.[132]

79. The current GUIC rates (excluding the portion associated with the out-of-period adjustment or true-up component) would produce revenue of $790,153.[133] Consequently, the net increase in GP's proposed required revenue recovery was calculated as $2,849,686 ($3,639,839 less $790,153 = $2,849,686).[134]

80. GP has calculated its 2020 revenue deficiency as follows:[135]

[129] Ex. GP-10 at 5 (Kivisto Direct)
[130] Ex. GP-21 at 4 (Jacobson Direct).
[131] *Id*. at 5.
[132] *Id*.
[133] *Id*.
[134] *Id*.
[135] Ex. GP-2 (Initial Filing, Vol. III, Statement A – Jurisdictional and Financial Summary at 1.) (Sept. 27, 2019).

	Per Books	Projected 2019	Projected 2020
Rate Base	$25,477,480	$29,263,477	$31,686,174
Required Rate of Return	7.522%	7.383%	7.460%
Required Income	$1,916,416	$2,160,523	$2,363,789
Operating Income	604,015	530,441	(229,888)
Income Deficiency	$1,312,401	$1,630,082	$2,593,677
Gross Revenue Conversion Factor	1.403351	1.403351	1.403351
Total Revenue Deficiency	$1,841,759	$2,287,577	$3,639,839
GUIC in current rates, excluding out-of-period true up			$790,153
Net increase in required recovery			$2,849,686

VI. CALCULATION OF EXPENSES

81. The DOC-DER conducted a financial investigation which included a review of: GP's actual 2016 through 2018 expenses;[136] capital budget deviation reports for years 2016, 2017, and 2018; budget deviation reports for operation and maintenance (O&M) costs for years 2016, 2017 and 2018; all adjustments proposed by the Company to its actual 2018 results in the development of its 2020 test year; the Commission's Order in GP's 2015 Rate Case; relevant Commission orders in other rate cases since GP's 2015 Rate Case; and the Gas Utility Infrastructure Cost (GUIC) rider.

82. The DOC-DER specifically analyzed the following expenses: incentive compensation; bonuses and commissions; net plant additions; plant retirements; materials and supplies; gas in storage; prepayments; unamortized loss on debt redemption; miscellaneous tools (account 394.1); common plant land and land rights; accumulated deferred income taxes (ADIT); regulatory assets and liabilities; asset addition depreciation lives; other revenue; labor costs; active benefit expenses; subcontracted labor costs; uncollectible accounts; industry dues; insurance expenses; all other O&M expenses; non-qualified pension amounts; labor inflation rates used by the Company; and the rate case expenses estimated.

83. In its analysis, the DOC-DER and OAG raised issues related to certain expenses and financial matters in calculating the revenue requirement. Ultimately, GP and the DOC-DER reached agreements with respect to the amounts calculated by the Company related to the following expenses: employee benefits expenses;

[136] As documented in the Company's Minnesota jurisdictional annual reports provided to the DOC-DER and the Commission.

subcontracted labor costs; employee bonus expenses; interest expense synchronization; and the CIP expense and CCRA Adjustment Factor.

84. The parties were unable to resolve their disagreements related to certain association dues paid, the handling of incentive compensation; and the handling of rate cases expenses estimated but not actually incurred.

85. The following two sections summarize the issued raised by the DOC-DER and OAG related to expenses or financial issues. Section VII addresses expense issues that remain disputed between the parties. Section VIII addresses expense and financial issues that were resolved by the parties.

VII. CONTESTED EXPENSE ISSUES

A. Dues to Minnesota Utilities Investor Association and Edison Electric Institute

86. In GP's Initial Filing, the Company provided an itemized schedule of all industry dues paid in 2018, totaling $34,589, along with projections for each dues amount in 2019, totaling $41,872.[137]

87. In calculating the revenue requirement for the test year, GP used the actual 2019 dues total of $41,872, asserting that dues will remain flat in 2020.[138] According to GP, this amount excludes dues for organizations not directly related to Minnesota gas operations and the portion of the dues associated with lobbying (to the extent that the organizations identify which portion of the dues are associated with lobbying).[139]

88. Within this dues amount, GP include dues to be paid to the Minnesota Utilities Investor Association (MUI) in the amount of $11,500, and dues to be paid to the Edison Electric Institute (EEI) in the amount of $464.[140]

89. The OAG opposes the allowance of both the MUI and EEI dues.[141]

90. The DOC-DER opposed only the allowance of the MUI dues.[142]

91. According to GP, the MUI is:

---

[137] Ex. GP-2 (Vol. III, Statement C, Schedule C-2 at 20 of 27) (Sept. 27, 2019).
[138] *Id.*
[139] Ex. GP-21 at 22 (Jacobson Direct).
[140] *Id.*; Ex. GP-2 (Vol. III, Statement C, Schedule C-2 at 20 of 27) (Sept. 27, 2019).
[141] Ex. OAG-1 at 7-9 (Lebens Direct); Ex. OAG-2 at 7-9 (Lebens Surrebuttal); Ex OAG-3 (Lebens Summary).
[142] Ex. DER-6 at 7-10 (Byrne Direct); Ex. DER-14 at 6-10 (Byrne Surrebuttal); Ex. DER-21 (Byrne Summary).

a grassroots organization, established in 1990, to present the interests of individuals and business investors owning shares in utility companies operating in Minnesota. MUI's principal objective is to enhance the voice and impact of utility shareholders in the development of federal, regional, and state legislative and regulatory policy.[143]

92. The MUI website describes the types of meeting and activities facilitated by the organization, including local meetings, a statewide annual meeting, energy facility tours, and an annual "Day at the Capitol" with arranged appointments with legislators.[144] For these meetings, Supporting Membership-level members may bring a spouse or guest for free. The event includes catered meals and transportation to various sites around the state.[145]

93. As a trade organization, membership in the group is optional[146] and limited to utility shareholders.[147] It exists to advance the interests of investors, not ratepayers.

94. While GP contends that "MUI focuses on legislation and regulatory policy that impacts utilities and, directly and indirectly, impacts utility customers,"[148] the Company has not established that members in the MUI benefits ratepayers. Specifically, GP has not shown that MUI's activities assist the Company in recruiting additional equity investors; nor has the Company provided evidence that MUI provides education or training to enrich its employees' knowledge or skills in providing safe and reliable utility service. For this reason, the Company is not entitled to recover even 50 percent of this expense.

95. A review of MUI's activities, purpose, and mission establishes that the organization is primarily focused on advancing the interests of utility shareholders in the regulatory policy-making and law-making process.[149] As a result, it does not provide benefits to ratepayers[150] and, thus, should not be included in the calculation of the revenue requirement.

96. With respect to the $464 dues for EEI, GP contends that these dues were related to EEI's affiliate Utility Solid Waste Activities Group (USWAG), an informal consortium of utility companies and other organizations, including the American Gas Association.[151] According to GP, the "USWAG is responsible for addressing solid and hazardous waste issues on behalf of the utility industry and is utilized by Great Plains in

---

143 Ex. GP-21, TRJ-1 at 3 (Jacobson Direct).
144 Ex. DER-6 at 8, ACB-3 (Byrne Direct).
145 *Id*.
146 Ex. DER-14 at 8 (Byrne Surrebuttal).
147 *Id*.
148 Ex. GP-23 at 2-3 (Jacobson Rebuttal).
149 Ex. DER-14 at 9, ACB-3 (Byrne Surrebuttal).
150 *Id.*
151 Ex. GP-23 at 3 (Jacobson Rebuttal).

a number of way specifically for natural gas operations."[152] However, the Company provides no evidence of how the USWAG is utilized by GP for its natural gas operations.

97. EEI is a group "that represents all U.S. investor-owned electric companies."[153] GP is a natural gas company, not an electric company. Thus, GP's ratepayers should not be responsible for the cost of dues for an organization primarily focused on representing the interests of electric companies. Consequently, this expense should be disallowed by the Commission.

98. Minnesota Stat. § 216B.03 (2018) requires that rates be just and reasonable, and that any doubt as to reasonableness be resolved in the ratepayer's favor. Here, GP has failed to show that it is reasonable for ratepayers to pay for the dues of the MUI and EEI. Accordingly, the Judge recommends excluding these dues, totaling $11,964, from the calculation of GP's revenue requirement.

B. Employee Incentive Compensation

99. GP determined its labor expenses using the actual labor costs for the 12 months ending December 31, 2018, and then adjusted them to remove labor expenses related to CIP, corporate allocations, and stock compensation.[154] The Company then projected a 2019 increase of 3.46 percent applied to 2018 "straight time," "premium time," and vacation expenses.[155] Bonuses and commissions were adjusted to reflect the removal of all stock compensation, with the remainder projected as not increasing for 2019.[156] Incentive compensation was projected at 9.50 percent of the 2019 straight time labor and vacation expenses, and assumes that no class receives an incentive payout greater than 15 percent of its annual salary.[157]

100. The 2020 test year labor expense was developed by applying the same projected increase in total labor costs to straight time, premium time, bonuses, commissions, and vacation as used in 2019. Incentive compensation was again projected at 9.50 percent of the projected 2020 straight time labor and vacation amount.[158]

101. GP and the DOC-DER do not disagree as to the calculation of employee benefits (including medical and dental insurance, pension, post-retirement, 401K, workers' compensation insurance, and "other" benefits). The only dispute between the parties is the amount of incentive compensation to be included in the labor expenses.

---

[152] *Id.*
[153] Ex. OAG-2 at 7, fn. 8 (Lebens Surrebuttal).
[154] Ex. GP-21 at 18 (Jacobson Direct).
[155] *Id.*
[156] *Id.*
[157] *Id.*
[158] *Id.*

102. The Company calculates the 2020 test year incentive compensation amount to be $261,892.[159] This amount is based on the use of a 9.50 percent incentive compensation rate applied to the 2020 test year straight time and vacation labor expenses.[160] The 9.5 percent incentive compensation rate was the result of dividing the total incentive compensation payout, based on the 100 percent target level of those in each job classification, capped at 15 percent of salary, by the total salary of all job classifications eligible for incentive compensation.[161]

103. The DOC-DER agrees with the Company's calculation of incentive compensation, provided that the Company file an annual incentive compensation report and, if required by the Commission, refund to ratepayers incentive compensation the Company does not pay to employees each year. [162]

104. GP opposes these conditions.[163] According to GP, because the Company will not be able to recover additional amounts if actual incentive compensation paid exceeds the amounts projected in this proceeding, the Company argues that it should not be required to pay back amounts if it does not pay out the projected amount each year.[164] Consequently, the Company characterizes such a refund as a "non-reciprocal single-issue" practice.[165] Moreover, GP argues that filing an annual incentive report would be an "administrative burden" for the Company.[166]

105. Since 1994, the Commission has required other investor-owned utilities, including Xcel Energy, Minnesota Power, and CenterPoint Energy, to track payments of incentive compensation, file annual incentive compensation reports, and refund amounts not actually paid under their incentive compensation programs.[167]

106. The Commission first adopted this policy in Xcel Energy's 1992 Electric Rate Case.[168] Xcel Energy continues to track, file an annual report, and refund unpaid

---

[159] Ex. DER-7 at 8 (Lusti Direct); Ex. GP-2 (Vol. III, Statement C, Schedule C-2, page 10 of 27).
[160] Ex. DER-7 at 8-9, DVL-8 (Lusti Direct) (Great Plains' Response to Department Information Request (IR) No. 116).
[161] Ex. DER-7 at 9, DVL-8 (Lusti Direct).
[162] Ex. DER-7 at 8-12 (Lusti Direct); Ex. DER-15 at 4-7 (Lusti Surrebuttal); Ex. DER-22 (Lusti Summary).
[163] Ex. GP-23 at 5 (Jacobson Rebuttal).
[164] *Id*.
[165] *Id*.
[166] *Id*. at 6.
[167] Ex. DER-7 at 10 (Lusti Direct).
[168] *Id.* at 11 (*citing In the Matter of the Application of Northern States Power Company for Authority to Increase Its Rates for Electric Service in the State of Minnesota (Xcel 1992 Rate Case)* MPUC Docket No. E002/GR-92-1185, ORDER AFTER RECONSIDERATION at 25, Ordering Paragraphs 2 and 3 (Jan. 14, 1994)).

incentive compensation in its rate cases.[169] Xcel Energy filed its most recent annual incentive compensation report on May 31, 2019.[170]

107. Minnesota Power also tracks, files annual reports, and refunds unpaid annual incentive compensation. In Minnesota Power's most recent rate case, the Commission ordered the company, to ". . . continue to provide customer refunds in the event that actual payouts are lower than the level approved in rates."[171] In accordance with the Commission order, on July 23, 2019, Minnesota Power filed its annual incentive compensation report for 2018.[172]

108. Similarly, CenterPoint Energy tracks annual incentive compensation, files reports, and is required to refund unpaid amounts. On April 15, 2019, CenterPoint Energy filed its most recent annual incentive compensation report,[173] pursuant to the Commission's requirements in CenterPoint Energy rate cases.[174]

109. Notably, in 2015, GP recovered from ratepayers amounts for incentive compensation that were not actually paid to employees.[175]

110. Due to these facts, the DOC-DER recommends that, since the Company's proposed test year incentive compensation expense was based upon all employees earning their individual 100 percent of target-level incentive compensation (capped at 15 percent of salary), it is reasonable for the Company to refund to ratepayers the amount of incentive compensation that is approved and included in base rates but is not paid annually to employees under the program.[176]

111. To determine the amount of actual incentive compensation paid that is recoverable from ratepayers, the DOC-DER suggests that the Company apply the 15 percent cap to each individual employee's salary.[177] The DOC-DER urges the Commission to require GP to file an annual report on incentive compensation within

[169] *Id*.
[170] *Id*. (citing *Northern States Power Co. Report on the Operation and Performance of its 2018 Incentive Compensation Plan*, MPUC Docket No. E,G-002/M-19-375, *Annual Report and Refund Proposal*, (May 31, 2019)).
[171] *Id*. (citing *In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Utility Service in Minnesota*, MPUC Docket No. E015/GR-16-664, (March 12, 2018) Order Point 22).
[172] *Id*. (citing *Minnesota Power's Compliance Filing-Incentive Compensation* MPUC Docket No. E015/GR-16-664 (July 23, 2019).)
[173] *Id*. at 12 (citing *CenterPoint Annual Incentive Compensation Compliance Filing,* MPUC Docket No. G008/GR-17-285 (Apr. 15, 2019).)
[174] *Id*.
[175] *Id.* (citing *In the Matter of the Application of Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc. for Authority to Increase Rates for Natural Gas Service in Minnesota* (MPUC Docket No. G004/GR-15-879)).
[176] *Id*. at 9.
[177] *Id*.

30 days after incentive compensation is normally scheduled for payout.[178] According to the DOC-DER, the report should include, at a minimum, the following:

- A description of the incentive compensation plan;

- The accounting of amounts of unpaid incentive compensation built into rates to be returned to ratepayers;

- An evaluation of the incentive plan's success in meeting its stated goals, including the payout ratio;

- A proposal for refund, if applicable; and,

- Identification of each performance indicator and its associated scorecard information, such as the measure, the goal for various attainment levels (threshold, target, maximum), its funding weight and the actual result achieved; and to report the overall plan payout percentage attained relative to the target goal of 100%.[179]

112. The Administrative Law Judge concurs with the recommendations of the DOC-DER. Ratepayers should not be responsible for costs that are not actually incurred by the utility. Given the Commission's past practice of requiring utilities to file incentive compensation reports, as well as GP's recent history of not paying such incentive compensation despite recovering such amount from ratepayers in 2015, it is reasonable to for the Commission to impose the conditions recommended by the DOC-DER.

113. Accordingly, the Administrative Law Judge adopts the amount of incentive compensation included in GP's proposed rate base for test year 2020 ($261,892). However, the Judge recommends that the Commission require the Company to file an annual report identifying the amount of incentive compensation actually paid out each year, along with the other information recommended by the DOC-DER. Upon review of the annual report, the Commission can then determine whether a refund to ratepayers is appropriate and what amount, if any, should be refunded.

C. Rate Case Expenses

114. GP estimates that the amount of rate case expenses incurred by the Company in this proceeding will be $592,555.[180] The estimated expenses include six categories of costs:[181]

(1) rate of return consulting fees;

[178] *Id*. at 9-10.
[179] *Id*.; Ex. DER-15 at 4 (Lusti Surrebuttal).
[180] Ex. GP-3 (Statement C, Workpapers, Schedule C-2 at 19) (Sept. 27, 2019).
[181] Ex. DER-7 at 13 (Lusti Direct).

(2) outside legal fees;

(3) GP's staff hearing expenses;

(4) Montana-Dakota staff public input meeting expense;

(5) state agency fees; and,

(6) administrative costs (Federal Express and miscellaneous).

115. The DOC-DER does not dispute the Company's estimate of these expenses.[182] The DOC-DER also does not dispute GP's proposal to use to a four-year amortization period to collect the expense.[183]

116. GP and the DOC-DER disagree, however, whether GP should track any over-recovery from ratepayers of rate case expenses, and whether the Company should apply that credit to the revenue requirement in its next rate case.[184] The DOC-DER recommends that the Commission should follow its own action from GP's 2015 Rate Case[185] and require the Company to track the over-recovery of expenses and credit that amount to the revenue requirement in its next case.[186] GP opposes that recommendation asserts that requiring the Company to track one expense amounts to a "single issue ratemaking." [187]

117. The Administrative Law Judge rejects GP's argument. As with incentive compensation not paid, the Judge recommends that the Commission require the Company to track and calculate the final rate making expenses, and then credit back any amount exceeding$592,555 in its next rate case.

VIII. RESOLVED EXPENSE AND FINANCIAL ISSUES

A. Benefits Expense

118. GP's initial filing proposed 2020 test year benefits expense consisting of several items, in the projected amounts shown below:[188]

---

[182] *Id*. at 14 (Lusti Direct).
[183] Ex. GP-21 at 23 (Jacobson Direct); Ex. DER-7 at 14 (Lusti Direct).
[184] Ex. GP-23 at 6 (Jacobson Rebuttal); Ex. DER-7 at 14 (Lusti Direct); Ex. DER-15 at 7-8 (Lusti Surrebuttal); Ex. DER-22 (Lusti Summary Statement).
[185] *In the Matter of the Petition by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota,* MPUC Docket No. G004/GR-15-879, FINDINGS OF FACT, CONCLUSIONS, AND ORDER at point 8 (Sept. 6, 2016).
[186] Ex. DER-7 at 14 (Lusti Direct); Ex. DER-15 at 7-8 (Lusti Surrebuttal); Ex. DER-22 (Lusti Summary Statement).
[187] Ex. GP-23 at 6 (Jacobson Rebuttal).
[188] Ex. GP-21 at 19 (Jacobson Direct); Ex. DER-6 at 4 (Byrne Direct) (citing Ex. GP-2 (Vol. III, Statement C, schedule C-2, at 13 of 27)).

Expense Category	Amount
Medical/Dental	$504,227
Pension	$13,156
Post-Retirement	($93,337)
401(k)	$279,658
Workers Compensation	$20,314
Other Benefits	$3,596
Total	$727,614

119. In response to a DOC-DER information request (IR), GP provided historical, actual benefits expenses for 2016 through 2018, and an updated projection for 2019 that included the 2019 calendar year actual benefits expenses (where actual data was available).[189] The updated information is set forth below:[190]

Historical and Updated Benefits Expenses

Year	2016	2017	2018	IR No. 106 Projected 2019
Medical/Dental	$377,404	$408,415	$398,409	$458,090
Pension	$21,525	$14,972	$19,375	$61,633
Post Retirement	$(7,266)	$(20,901)	$(68,048)	$(92,112)
401(k)	$269,808	$284,671	$252,111	$248,111
Workers Compensation	$30,349	$18,464	$18,913	$22,126
Other Benefits	$4,482	$5,299	$3,199	$3,505
Total	$696,302	$710,920	$623,959	$701,353

120. The updated projected 2019 benefits expense of $701,353 is $33,879 less than the amount forecasted for 2019 in the Company's Initial Filing ($735,232).[191]

121. The DOC-DER determined that the amount of $701,353 was more consistent with the Company's historical expenses since its last rate case.[192] In addition, the individual category percentage increases proposed by GP to estimate 2020 test year expenses were also more consistent with previous year-over-year increases for such non-actuarial expenses.[193]

---

[189] Ex. DER-6 at 4 (Byrne Direct) (citing DOC-DER IR No. 106).
[190] *Id*. at 4-5, ACB-1.
[191] *Id*. at 5. (The amount was calculated using actual expenses through October 2019, with annualized amounts for the remaining two months of the year.)
[192] *Id.* at 5-6.
[193] *Id.*

122. The DOC-DER concluded that it was reasonable to base the pension and post-retirement expense estimates on actuarial estimates, and to base the remaining expense estimates on reasonable percentage increases from the 2019 projections.[194] Accordingly, the DOC-DER recommended that the 2020 test year be calculated by: (1) substituting the actuarial estimates for pension and post-retirement benefits; (2) applying the Company's proposed six-percent increase for the medical/dental employee expenses; and (3) using a 3.5-percent increase for 401(k), workers' compensation, and other benefit expenses to the updated projected 2019 amounts provided in response to the DOC-DER IR No. 106.[195]

123. The DOC-DER calculation resulted in an overall downward adjustment of the test-year expense in the amount of $38,897, as shown below:[196]

DOC-DER Calculation of Test-Year Benefits Expenses[197]

Expense Category	GP-Proposed 2020 TY	IR No. 106 Projected 2019	Adjustment	DOC DER Determined Amount	DOC DER Adjustment to 2020 TY
Medical/Dental	$504,227	$458,090	+ 6%	$485,575	($18,652)
Pension	$13,156	$61,633	Actuarial	$13,156	$ -
Post-retirement	($93,337)	$(92,112)	Actuarial	($93,337)	$ -
401(k)	$279,658	$248,111	+ 3.5%	$256,795	($22,863)
Workers Compensation	$20,314	$22,126	+ 3.5%	$22,900	$2,586
Other Benefits	$3,596	$3,505	+ 3.5%	$3,628	$32
Total	$727,614	$701,353		$688,717	($38,897)

124. GP agreed with the DOC-DER adjustments, which reduce the Company's initially-proposed 2020 test year benefits expense of $727,614 by $38,897, to a final figure of $688,717.[198] Accordingly, the parties agree to a revised total benefits expense total of $688,717, which should be used to determine the Company's total revenue requirement.[199]

B. Subcontracted Labor Expense

125. In its initial filing, GP calculated its proposed 2020 test year expense for subcontracted labor by estimating its 2019 subcontract labor expense to be $515,563

[194] *Id.* at 6.
[195] *Id.*
[196] *Id.*
[197] *Id.* at 7, ACB-2 (Byrne Direct).
[198] Ex. GP-23 at 3-4 (Jacobson Rebuttal); Ex. DER-14 at 3 (Byrne Surrebuttal).
[199] Ex. GP-21 at 19 (Jacobson Direct); Ex. DER-6 at 3-7, ACB-2 (Byrne Direct); Ex. DER-14 at 2-3 (Byrne Surrebuttal); Ex. GP-23 at 3-4 and TRJ-3 (Jacobson Rebuttal); Ex. GP-24 (Jacobson Summary); Ex. DER-21 (Byrne Summary).

and then applying a 1.94 percent “inflation factor.”[200] The result was a proposed 2020 test year amount of $525,564.201.[202]

126. Upon review of these figures, the DOC-DER determined that the Company’s estimated 2019 subcontracted labor expense did not appear reasonable when compared with the Company’s 2018 actual expense for the same item.[203] Specifically, GP’s 2018 subcontractor expense for Minnesota was $464,187, which is approximately $50,000 less than the 2019 amount the Company’s initial filing projected for 2019 ($515,563).[204]

127. Consequently, DOC-DER IR No. 122 requested 2016 through 2018 historical actuals for subcontractor expenses, as well as an updated 2019 projection for the same expense.[205] The Company provided the actual amounts for 2016, 2017, and 2018, as well as an updated projection for 2019, as set forth in the table below:

Historical and Updated Subcontract Labor[206]

Year	Amount
2016 Actual	$399,118
2017 Actual	$416,029
2018 Actual	$464,187
Updated Projected 2019	$435,715
2020 Proposed Test Year	$525,564

128. This data shows that the Company’s subcontracted labor expense increased from 2016 to 2018, but that the updated projection for 2019 showed a decrease in expense from 2018.[207] In fact, the Company’s updated projection for 2019 was approximately $80,000 less than the amount the Company had projected in its initial filing.[208]

129. As a result of the data provided in response to IR No. 122 and the Company’s failure to provide any information to justify the significantly higher expense for 2020, the DOC-DER concluded that the Company’s proposed 2020 test year subcontracted labor expense amount was not reasonable.[209]

---

[200] Ex. DER-6 at 11 (Byrne Direct).
[201] Ex. GP-2 (Initial Filing, Vol. III, Statement C, Schedule C-2, at 14 of 27) (Sept. 27, 2019).
[202] *Id.*
[203] Ex. DER-6 at 11 (Byrne Direct) (citing Ex. GP-2 (Vol. III, Statement C, Schedule C-2, at 14 of 27)).
[204] *Id*.
[205] *Id.*
[206] *Id.* at 11-12, ACB-4 (Byrne Direct).
[207] *Id*. at 12.
[208] *Id.*
[209] *Id.*

130. The DOC-DER recommended that, because the Company's historical expenses increased through 2018, it would be reasonable for the Company to use the updated 2019 projected amount and apply the 1.94 percent inflation factor that GP used to calculate its initial test year proposal, to determine a 2020 test year figure.[210] Using this method results in a 2020 test year subcontracted labor expense of $444,168, which is a downward adjustment of $81,397 from GP's proposed test year expense of $525,564.[211] GP agreed with the DOC-DER's recommended adjustment.[212]

131. The estimated financial impact of this stipulated reduced test-year operation and maintenance (O&M) expenses (of which subcontracted labor is a part) is a reduction of $81,397 in the revenue requirement.[213]

C. Conservation Improvement Program (CIP) Expense and Conservation Cost Recovery Adjustment (CCRA) Factor

132. There are two contested issues with respect to the Conservation Improvement Program (CIP) expense and the Conservation Cost Recovery Adjustment (CCRA) Factor. The first is the issue of the appropriate amount of CIP test year expense. The second relates to the Company's proposal to make a change to the CCRA Factor.[214]

133. As to the first issue, GP proposed to include in its 2020 test year $566,621 in CIP expense, which is the same amount as its 2018 actual CIP expense.[215] In its review, the DOC-DER noted that GP's past CIP status reports[216] showed that the Company typically spent less than its authorized CIP budget, as shown in the table below:[217]

---

[210] *Id.* at 12-13 (*citing* footnotes of Ex. GP-2 (Initial Filing, Vol. III, Statement C, Schedule C-2, at 13 of 27) (Sept. 27, 2019)).
[211] *Id.* at 12-13, ACB-5 (Byrne Direct).
[212] Ex. GP-23 at 4 (Jacobson Rebuttal); Ex. DER-14 at 3-4 (Byrne Surrebuttal).
[213] Ex. DER-6, ACB-5 (Byrne Direct); Ex. DER-14 at 3 (Byrne Surrebuttal); Ex. DER-21 (Byrne Summary).
[214] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 22, 2019) (GP proposed a change to the CCRA Factor from the currently approved CCRA Factor amount of (.0337) to (.0599) in this general rate case rather than through a CIP tracker/DSM financial incentive docket.)
[215] Ex. GP-2 (Initial Filing, Vol. III, Statement C, Schedule C-2, at 17 of 27) (Sept. 27, 2019); Ex. GP-21 at 20 (Jacobson Direct); Ex. DER-6 at 13 (Byrne Direct) (Mr. Jacobson explained that "Schedule C-2, page 17 shows the base level of Conservation Improvement Program (CIP) expense that Great Plains has included in its distribution margin. Great Plains used the actual expense of $566,621 for 2019 and 2020 as included in Great Plains' annual Status Report in Docket No. G004/CIP-19-287. Great Plains used actual expenses, instead of the budget, because of the extension of the new CIP portfolio to 2021. Any differences from the base will be returned to or collected from customers through the CCRA.").
[216] Docket Nos. G004/CIP-12-573.01, G004/CIP-12-573.02, G004/CIP-12-573.03, G004/CIP-12-573.04, G004/CIP-16-121.01, G004/CIP-16-121.02.
[217] Ex. DER-6 at 14 (Byrne Direct).

GP's CIP Budgets and Expenditures

Year	Approved Budget	Actual Spend
2013	$821,691	$378,794
2014	$827,718	$327,380
2015	$1,012,597	$724,644
2016	$832,597	$642,143
2017	$885,396	$403,118
2018	$887,408	$566,621
2019	$902,858	

134. Based upon this data, the DOC-DER concluded that the Company's proposal of $566,621 was reasonable to include in the 2020 test year CIP expenses, because that amount reflects actual 2018 CIP expenditures.[218] The DOC-DER further opined that it would be unreasonable for the Company to include in the test year expenditures the amounts that GP budgeted for 2019 because, historically, the Company spent less than budgeted.[219] Moreover, any amounts incurred over the 2018 actual expenses incurred could be collected through the CCRC Factor each year.[220]

135. With respect to the second issue, the CCRC Factor, GP's Initial Filing proposed not only to update the CCRC in this rate case, but also to change the CCRA Factor so that the CCRC and the CCRA Factor, combined, would recover the same amount that the CCRC and the CCRA Factor, combined, were recovering prior to this rate case.[221]

136. The DOC-DER concluded that such a proposal was not reasonable because, when calculating the CCRA Factor each year, the Commission practice requires a "thorough review" of the Company's current CIP tracker[222] balance.[223] Here, GP provided no information about the CIP tracker balance to support its proposed

---

[218] *Id.*
[219] *Id*.
[220] *Id*.
[221] Ex. GP-31 at 12 (Bosch Direct); Ex. DER-6 at 14 (Byrne Direct).
[222] The CIP cost tracker records revenues collected through the CCRC and the CCRA Factor, the actual CIP expenditures, the Commission-approved financial incentives (financial "rewards" to utilities as an incentive to achieve certain levels of energy savings), the carrying charges, and any adjustments that may occur over the period the CCRA is in place. Ex. DER-6 at 15 (Byrne Direct).
[223] Ex. DER-6 at 16 (Byrne Direct) (*citing In the Matter of Great Plains Natural Gas Co.'s 2015 Demand Side Management Financial Incentive and Annual Filing to Update the CIP Rider*, MPUC Docket No. G004/M-16-384, ORDER APPROVING TRACKER ACCOUNT, APPROVING FINANCIAL INCENTIVE, SETTING CARRYING-CHARGE RATE, AND SETTING CONSERVATION COST RECOVERY ADJUSTMENT at 4, fn.5 (Nov. 23, 2016)) (The Commission determined that, "The Department also claimed that Great Plains had been charging a CCRA not approved by the Commission. Great Plains disagreed, stating that its current -$0.0079/Dth CCRA was part of the interim tariffs approved by the Commission in the Company's recent rate case. However, the Commission clarifies that the CCRA *should be adjusted only after a thorough review of Great Plains' CIP tracker.*") (emphasis added).

change to the CCRA Factor.[224] Thus, while updating the CCRA Factor at the time the CCRC is revised in a rate case may be reasonable, the method the Company proposed to make such change was not supported because it was not based on an assessment of the current CIP tracker balance.[225] Consequently, the DOC-DER recommended that the Commission approve GP's proposed CCRC, but deny the Company's request to update the CCRA Factor in this proceeding.[226]

137. GP concurs with the DOC-DER's recommendation. According to Company witness Stephanie Bosch, "Great Plains does agree that the CCRA should be updated in its next tracker filing to better match the actual CIP expenditures, financial incentives, carrying charges, and adjustments that may occur over the period the CCRA is in place. . . .Great Plains next CIP tracker filing will be filed no later than May 1, 2020."[227]

138. Thus, the DOC-DER and GP agree that the Company's proposed CIP expense of $566,621 should be used as the basis for its CCRC rate and that any changes to the CCRA Factor should be determined in the Company's next annual (2020) CIP tracker and financial incentive proceeding, rather than in the instant rate case.[228]

139. The Administrative Law Judge recommends that the Commission adopt this jointly-supported proposal.

D. Continuation of the Gas Utility Infrastructure Cost (GUIC) Rider

140. GP's Initial Filing proposed to include in base rates the costs associated with the assets currently being recovered in its approved GUIC rider adjustment factors established in MPUC Docket No. G-004/M-18-282.[229] GP also requested that the Commission approve the 2019 projects it had submitted in Docket No. 19-273,[230] and allow the Company to suspend the GUIC rider rate upon the implementation of interim

---

[224] *Id*. at 15.

[225] Moreover, GP's CCRA Factor did not change with implementation of interim rates, as proposed. GP's December 2, 2019 Interim Rates Compliance Filing in this case did not include the Conservation Improvement Program Adjustment Clause tariff, Sheet No. 5-111, that would state the current CCRC and CCRA Factor. Ex. DER-6 at 16 (Byrne Direct).

[226] Ex. DER-6 at 16 (Byrne Direct) (Under this recommendation, the Commission would consider any update to the CCRA Factor that may subsequently be needed in the Company's upcoming annual CIP tracker and financial incentive filing to be submitted by May 1, 2020); Ex. DER-14 at 4 (Byrne Surrebuttal); Ex. DER-21 (Byrne Summary).

[227] Ex. GP-32 at 2-3 (Bosch Rebuttal).

[228] Ex. GP-21 at 20 (Jacobson Direct); Ex. DER-6 at 13-16, 21 (Byrne Direct); Ex. GP-31 at 12 (Bosch Direct); Ex. GP-32 at 2-3 (Bosch Rebuttal); Ex. DER-21 (Byrne Summary).

[229] *Great Plains Natural Gas Co. (Great Plains), a Division of Montana-Dakota Utilities Co., Annual Report and Petition for approval of recovery of updated Gas Utility Infrastructure Costs (GUIC) under its GUIC Adjustment Tariff for 2018*, MPUC Docket No. G004/M-18-282.

[230] *Great Plains Natural Gas Co. (Great Plains), a Division of Montana-Dakota Utilities Co., Annual Report and Petition for approval of recovery of updated Gas Utility Infrastructure Costs (GUIC) under its GUIC Adjustment Tariff for 2019*, MPUC Docket No. G004/M-19-273.

rates because the Company had included those same 2019 projects in the rate base in this rate case.[231]

141. The Commission's Notice and Order for Hearing requires that parties develop a record regarding two issues: (1) the impact of suspending the GUIC rider; and (2) whether the Company intend to continue use of the GUIC rider subsequent to the rate case.[232]

142. GP initially planned to continue its GUIC rider during its rate case and incorporate the revenue requirement from rider-eligible assets at the end of the rate case.[233] However, upon requests from DOC-DER analysts, the Company agreed to roll its rider revenue requirements into its rate case at the beginning of its test year.[234]

143. Whether a utility incorporates its rider-eligible revenue requirements at the beginning or at the end of its test year ultimately has the same financial effect.[235] However, rolling the rider revenue requirements in at the beginning of the test year (and suspending the rider) leaves less opportunity for double recovery because it eliminates the need for a corresponding adjustment in the interim rate refund calculation.[236]

144. Incorporating the rider revenue requirements at the beginning of a utility's test year consists of two steps.[237] First, revenue to be collected through the rider during the test year is set to zero and is, instead, included in interim rates.[238] Second, the revenue requirement related to the rider-eligible assets are included in the utility's test year revenue deficiency.[239] According to DOC-DER witness Angela Byrne:

> While it may appear that rolling in a rider increases a utility's revenue requirements, practically speaking[,] the net effect on ratepayers is zero. This process merely changes the mechanism for recovery of previously-approved revenue requirements from the rate rider factor to base rates.[240]

145. Consequently, the DOC-DER does not object to the Company rolling its rider revenue requirements into this rate case at the beginning of the 2020 test year.[241]

146. As to the second of the Commission's questions -- whether GP intends to use the GUIC rider after the rate case, the Company's responded to DOC-DER IR

---

[231] Ex. GP-21 at 5 (Jacobson Direct).
[232] NOTICE OF AND ORDER FOR HEARING at 2 (Nov 22, 2019).
[233] Ex. DER-6 at 18 (Byrne Direct).
[234] *Id.*
[235] *Id*.
[236] *Id.*
[237] *Id.*
[238] *Id.*
[239] *Id.*
[240] *Id.*
[241] *Id.*

No. 102 in the affirmative.[242] The Company does plan to continue to utilize the GUIC rider after the rate case.[243]

147. The DOC-DER concluded that the Company's actions, and its explanation of intentions regarding its GUIC rider, align with the DOC-DER's understanding of how the GUIC rider should interact with GP's rate case.[244] The OAG did not take a position on the issue of the GUIC rider.

E. Rate Base: 2020 Beginning Balance for Calculating Average Rate Base

148. The test year rate base is a projection consisting of the average of the 2020 projected beginning and ending rate base balances.[245] The timing and schedule for this case (continuing through the end of calendar year 2020) allowed GP to update the 2020 beginning balance to reflect the 2019 actual ending balance.[246]

149. The DOC-DER recommended that the revenue requirement approved in this proceeding be based on GP's update of its 2020 beginning rate base balance to the actual amount, and that the Company's projected 2020 additions be held at the level the Company proposed in its initial case (in the amount of $4,645,785).[247]

150. GP agreed to these recommendations.[248] The adjustment for the 2019 year-end update resulted in an increase to the test-year rate base of $930,854.[249]

151. The DOC-DER recommends that the Commission approve this adjustment as just and reasonable.[250]

F. Cash Working Capital

152. GP did not calculate a cash working capital component in its base rate.[251] Although most investor-owned utilities perform a lead/lag study to calculate a cash

[242] *Id*. at 18-19.
[243] *Id.* (The response to IR No. 102 stated: "The Company plans to file an update in the Spring of 2020 that will focus on the true up of the over- or under-recovery in the rider's tracker balance as of December 31, 2019. The Company also plans to continue to utilize the GUIC rider for future recovery of GUIC-eligible projects beginning in 2021.")
[244] Ex. DER-6 at 17-19 (Byrne Direct); Ex. DER-14 at 5-6 (Byrne Surrebuttal); Ex. DER-21 (Byrne Summary).
[245] Ex. DER-6 at 17 (Byrne Direct).
[246] *Id.*
[247] Ex. DER-14 at 13, ACB-S-1 (Byrne Surrebuttal).
[248] *Id.* at 10-13, ACB-S-1 (Byrne Surrebuttal); Ex. DER-21 (Byrne Summary). Ex. GP-2, Statement B - Rate Base; Ex. GP-21 at 8-10 (Jacobson Direct); Ex. GP-23 at 4-5 (Jacobson Rebuttal); Ex. GP-24 (Jacobson Summary); Ex. DER-6 at 17 (Byrne Direct); Ex. DER-14 at 10-13, ACB-S-2 (Byrne Surrebuttal); Ex. DER-21 (Byrne Summary); Ex. DER-15 at 2, DVL-S-3, DVL-S-4, DVL-S-8, column (c) (Lusti Surrebuttal).
[249] Ex. DER-15 at 2, DVL-S-8, column (c) (Lusti Surrebuttal).
[250] Ex. DER-14 at 15 (Byrne Surrebuttal).

working capital component of their rate base, GP historically has not performed such a study.[252] Thus, the Company did not include cash working capital in its test-year rate base.[253]

153. The DOC-DER concluded that there was no need for the Company to be required to perform such a study for the purposes of this rate case.[254]

G. Bonus Expense

154. The amount of bonuses and commissions GP included in its 2020 test year expenses was $9,509.[255]

155. The DOC-DER agreed that $9,509 was a reasonable amount of bonuses and commissions to include in the test year expenses because the costs included sign-on and relocation bonuses, referral awards, retirement awards, and service awards,[256] but not long-term incentive compensation.[257]

H. Interest Expense Synchronization

156. GP calculated its interest-expense deduction for test year income tax purposes by multiplying its rate base by the weighted cost of long-term and short-term debt, which is 2.277 percent.[258]

157. The DOC-DER agreed with this calculation method.[259] The DOC-DER's adjustment for interest synchronization was calculated as follows:[260]

DER Rate Base		$32,617,028
Weighted Cost of Debt (short and long-term)		**2.277%**
DER Interest	$	742,690
GP Interest	$	721,494
DER Interest Deduction Adj.	$	21,196
DER Taxable Income Adj.	$	(21,196)
Tax Rate		0.2874
Interest Adjustment	**$**	**(6,092)**

251 Ex. DER-7 at 6 (Lusti Direct).
252 *Id.* at 7.
253 *Id.*
254 Ex. DER-7 at 7 (Lusti Direct).
255 Ex. GP-2 (Vol. III, Statement C, Schedule C-2, at 10 of 27) (Sept. 27, 2019); Ex. DER-7 at 12-13 (Lusti Direct).
256 Ex. DER-7 at DVL-9 (Lusti Direct); (GP Response to DOC-DER IR No. 117).
257 *Id.* at 13 (Lusti Direct).
258 Ex. GP-2 (Statement C, Operating Income, Schedule C-5 at 2 of 5) (Sept. 27, 2019); Ex. GP-21 at 25 (Jacobson Direct).
259 Ex. DER-7 at 15 (Lusti Direct).
260 Ex. DER-15 at DVL-S-7 (Lusti Surrebuttal).

158. As set forth above, the adjustment to the test year federal and state income tax results in a $6,092 decrease to the test year income tax.[261]

IX. CAPITAL STRUCTURE

159. The term "capital structure" refers to the combination of short-term debt, long-term debt, and equity that a company uses to finance its activities.[262] The ratio between debt and equity that a rate-regulated utility chooses will affect its overall rate of return.[263]

A. Debt-to-Equity Ratio

160. Generally, a utility's overall cost of capital is the average of the costs of long-term debt, short-term debt, and equity it has, weighted by the amount of each type of financing that it uses.[264] Thus, to arrive at the cost of capital (the overall rate of return), it is necessary to determine the reasonable ratios of long-term debt, short-term debt, and common stock equity for GP overall.[265]

161. GP proposed to establish a capital structure consisting of 50.815 percent common equity, 4.053 percent short-term debt, and 45.132 percent long-term debt.[266] The Company considered the mean proportions of common equity, preferred equity, short-term debt, and long-term debt for the most recent year for each of the companies in its proxy group to develop a reasonable capital structure.[267] GP also considered credit rating agency expectations in developing its proposal.[268]

162. The DOC-DER compared the Company's proposed capital structure to the average capital structure of companies in the DOC-DER's Proxy Group (selection and determination of the parties' proxy groups is discussed in Section IX, B, 4 below).[269] The following is a summary of GP's capital structure and the capital structures of the members of the DOC-DER Proxy Group as of the end of their most recent fiscal years:[270]

[261] *Id*. at 8.
[262] Ex. DER-1 at 38 (Addonizio Direct).
[263] *Id*.
[264] *Id*. at 39.
[265] *Id*.
[266] Ex. GP-14 at 107 (Bulkley Direct).
[267] *Id.*
[268] *Id.* at 108.
[269] Ex. DER-1 at 40 (Addonizio Direct).
[270] *Id*. at Table 8.

Summary of GP's Proposed Capital Structure and Capital Structures of DER Proxy Group Members

	2016 Capital Structure Ratios			
Company	Short-Term Debt	Long-Term Debt	Preferred and Other Equity	Common Equity
Great Plains	4.05%	45.13%	0.00%	50.82%
ATO	4.77%	36.22%	0.00%	59.01%
NWN	12.68%	42.89%	0.00%	44.43%
OGS	8.26%	35.44%	0.00%	56.31%
SR	13.74%	39.24%	4.47%	42.54%
SWX	3.29%	46.27%	1.76%	48.69%
Minimum	3.29%	35.44%	0.00%	42.54%
Average	8.55%	40.01%	1.25%	50.19%
Maximum	13.74%	46.27%	4.47%	59.01%

163. The DOC-DER determined that GP's proposed equity ratio was almost equal to the DOC-DER Proxy Group's average, and its short- and long-term debt ratios were within the ranges of the DOC-DER Proxy Group.[271] Therefore, the DOC-DER concluded that GP's proposed capital structure is reasonable.[272]

164. With respect to cost of debt, GP proposed a short-term debt cost of 3.693 percent, including expense associated with the amortization of fees related to its revolving credit facility.[273]

165. The Company proposed a long-term debt cost of 4.712 percent, which is the average of the Company's estimated debt costs as of December 31, 2019, and December 31, 2020.[274] The DOC-DER noted that the Company's proposed cost of long-term debt reflected the issuance of $275 million in new long-term debt in late 2019 and 2020.[275]

166. The DOC-DER analyzed the Company's proposed short- and long-term debt costs and concluded that the Company's proposed debt costs were reasonable.[276]

[271] *Id*. at 40-41.
[272] *Id*. at 41.
[273] Ex. GP-2 (Statement D, Rate of Return – Cost of Capital, Schedule D-2 at 1) (Sept. 27, 2019).
[274] *Id*. at Schedule D-1 at 1.
[275] Ex. DER-1 at 42-43 (Addonizio Direct).
[276] *Id*.

167. Consequently, GP and the DOC-DER agree that it is reasonable for the capital structure to include costs of short-term debt of 3.693 percent long-term debt of 4.712 percent.[277]

B. Cost of Capital: Return on Equity (ROE)

1. Introduction

167. As part of this proceeding, the Commission must determine what constitutes a fair overall rate of return (ROR), also called cost of capital, for GP. ROR is calculated as the average of reasonable costs of long-term debt, short-term debt, and equity, weighted by the amount of each type of financing the Company uses.[278] In general, the cost of equity equals the return on equity (ROE) that GP must pay to induce equity investments in its regulated operations.

168. As set forth above, GP and the DOC-DER agree on the Company's amount of long-term debt, short-term debt, and common equity needed by GP to finance its operations. These amounts are based upon GP's actual capital structure. GP and the DOC-DER disagree, however, on the appropriate return on common equity for the Company.

169. Both GP and the DOC-DER presented expert witnesses on the subject of return on equity (ROE).

170. GP's expert witness on this issue was Ann Bulkley. Ms. Bulkley is a Senior Vice President at Concentric Energy Advisors, Inc.[279] She holds a bachelor's degree in economics and finance from Simmons College and a master's degree in economics from Boston University.[280] She has more than 20 years of experience consulting with energy companies.[281]

171. The DOC-DER's expert witness on ROE was Craig Addonizio. Mr. Addonizio is a Public Utilities Financial Analyst at the DOC-DER.[282] He as a bachelor's degree in economics from Carleton College and a master's degree in business administration from the University of Minnesota's Carlson School of Business.[283] He has approximately nine years of experience with the DOC-DER.[284]

---

[277] Ex. DER-9 at 2 (Addonizio Surrebuttal); Ex. GP-16 at 17 (Bulkley Rebuttal).
[278] DER-1 at 38-39 (Addonizio Direct).
[279] Ex. GP-14 at 1 (Bulkley Direct).
[280] *Id*. at 1-2.
[281] *Id*.
[282] Ex. DER-1 at 1 (Addonizio Direct).
[283] *Id*.
[284] *Id*.

172. GP asserts that a ROE of 10.2 percent is required for the Company to be able to raise capital on reasonable terms.[285] The DOC-DER disagrees and recommends a ROE of 8.82 percent.[286]

2. Return on Equity Principles

173. The Commission must set rates that are just and reasonable.[287] The determination of reasonableness involves a balancing of consumer and utility interests.

174. A reasonable rate enables a public utility not only to recover operating expenses, depreciation, and taxes, but also to compete for funds in capital markets (that is, to attract sufficient capital at reasonable terms). Minnesota law recognizes this principle when it defines a "fair and reasonable" rate of return as the rate, when multiplied by rate base, that will give a utility a reasonable return on its total investment.[288] This means that a fair return is one that enables the utility to attract sufficient capital (i.e., induce investors) at reasonable terms.[289] However, Minnesota law also requires that any doubt as to reasonableness should be resolved in favor of the consumer.[290] Accordingly, a ROR that provides the utility a greater return than is necessary to provide reliable service to consumers at reasonable rates would be excessive.

175. The principals of utility rate-setting have been established in two seminal Supreme Court cases: *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm's of W. Va* (Bluefield), 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas Co.* (Hope), 320 U.S. 591 (1944).

176. In *Bluefield*, the United States Supreme Court declared that a utility's return should be: (1) "reasonably sufficient to assure confidence in the financial soundness of the utility;" and (2) "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."[291]

177. In *Hope*, the Court reaffirmed and refined the *Bluefield* principles.[292] The Court reiterated that utilities are entitled to a return that: (1) is sufficient to cover operating expenses and capital costs of the business (including services on debt and dividends on stock); (2) is commensurate with returns on investments in other

---

[285] Ex. GP-14 at 8 (Bulkley Direct).
[286] Ex. DER-9 at 2 (Addonizio Surrebuttal).
[287] Minn. Stat. § 216B.03.
[288] Minn. Stat. § 216B.16, subd. 6.
[289] *Id*.
[290] Minn. Stat. § 216B.03 (emphasis added).
[291] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 692 (1923).
[292] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

enterprises having corresponding risks; (3) assures confidence in the financial integrity of the enterprise; and (4) allows the company to maintain its credit and attract capital.[293]

178. But the analysis of a reasonable return must also strike an equitable balance between investors and ratepayers. As explained by the Court in *Covington:*

> [S]tockholders are not the only persons whose rights or interests are to be considered. The rights of the public are not to be ignored. . . . The public cannot properly be subjected to unreasonable rates in order simply that stockholders may earn dividends.[294]

179. The decision in *Natural Gas Pipeline Company of America* reemphasized this point:

> The consumer interest cannot be disregarded in determining what is a 'just and reasonable' rate. Conceivably, a return to the company of the cost of service might not be "just and reasonable" to the public.[295]

3. Discounted Cash Flow Analysis (DCF)

180. To determine a reasonable ROE, both GP and the DOC-DER utilized a Discounted Case Flow (DCF) model, together with checks on the reasonableness of their respective results.

181. The DCF model is a method accepted by the Commission for evaluating the likely expectations of investors.[296] DCF analyses estimate a company's present value based on projections of how much money it will generate in the future.[297]

182. While the cost of equity cannot be observed directly, it can be estimated based upon a stock's expected dividend yield in one year and its dividend growth rate.[298] The DCF postulates that the current price of a stock is equal to the present value of all expected future dividends, discounted by the appropriate rate of return.[299]

---

[293] *Id*.
[294] *Covington and Lexington Turnpike Road Co. v. Sanford,* 164 U.S. 578, 596 (1896).
[295] *Fed. Power Comm'n v. Natural Gas Pipeline Co. of Am.*, 315 U.S. 575, 607 (1942) (Black, J., concurring).
[296] *See In re N. States Power Co., a Minn. Corp. & Wholly Owned Subsidiary of Xcel Energy Inc., for Auth. to Increase Rates for Nat. Gas Serv. in Minn*., MPUC Docket No. G-002/GR-06-1429, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 28 (2007 NSP Rate Case Order) (Sept. 10, 2007).
[297] DER-1 at 6 (Addonizio Direct).
[298] *Id*. at 6-7.
[299] *Id*. at 6.

183. There were two types of DCF models utilized by the parties in this proceeding: the Constant Growth DCF and the Two-Growth DCF.

184. The Constant Growth DCF model assumes constant growth of dividends over time and is reflected in the following formula:

> The expected (required) rate of return on equity = the expected dividend yield + the expected growth rate in dividends.[300]

185. In contrast, a Two-Stage DCF model assumes that dividends grow at one rate for a short period of time and then grow at a second, sustainable rate into perpetuity.[301]

186. GP cannot be analyzed directly with a DCF analysis because its stock is not publicly traded on any of the stock exchanges.[302] When a company's stock is not publicly traded, a DCF model can still be conducted but must be conducted on a "proxy group" of companies – companies with investment risks comparable to the risks of the subject company.[303] Both GP and the DOC-DER conducted their DCF analysis on a proxy group of publicly-traded companies.

4. Selection of Proxy Groups

187. The DOC-DER's expert, Mr. Addonizio, chose a group of proxy companies by applying the following criteria:

- The company is listed on the Compustat Research Insight data base and has a Standard Industrial Classification code of 4924 (natural gas distribution);
- The company is traded on a stock exchange;
- The company has a Standard & Poor's (S&P) credit ratings within the range of BBB to A+; and,
- The company received an average of at least 60 percent of their operating income from natural gas distribution during the most recent three years for which data is available.[304]

[300] *Id*. at 6-7.
[301] *Id*. at 7.
[302] *Id*. at 8.
[303] *Id*.
[304] *Id*. at 9-13.

188. Applying these criteria, Mr. Addonizio identified four publicly-traded companies as comparable proxy companies: Atmos Energy Corporation; Northwest Natural Holding Company; ONE Gas, Inc.; and Spire, Inc.[305]

189. Mr. Addonizio then looked to Value Line to identify other companies that are classified as natural gas companies.[306] Value Line identified four publicly-traded natural gas utilities, but only one company met both the credit rating and operating income thresholds listed above: Southwest Gas Holdings, Inc.[307]

190. Ultimately, Mr. Addonizio's screening process resulted in the following proxy group (DOC-DER Proxy Group):[308]

Company	Ticker
Atmos Energy Corporation	ATO
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
Spire Inc.	SR
Southwest Gas Holdings, Inc.	SWX

Source: Ex. DER-1, CMA-2 (Addonizio Direct)

191. GP's expert, Ms. Bulkley, also identified a proxy group for the Company's DCF analysis. Ms. Bulkley began with a group of 10 companies identified by Value Line as "natural gas distribution utilities."[309] Ms. Bulkley then applied the following criteria to select companies that:

- pay consistent quarterly cash dividends, because companies that do not cannot be analyzed using the Constant Growth DCF model;
- have investment-grade long-term issuer ratings from S&P and/or Moody's;
- are covered by at least two utility industry analysts;
- have positive long-term earnings growth forecasts from at least two utility industry equity analysts;

[305] *Id*. at 13.
[306] *Id*. at 12-13.
[307] *Id.* at 10-12.
[308] *Id.* at 13.
[309] Ex. GP-14 at 42 (Bulkley Direct).

- derive more than 70 percent of their total operating income from regulated operations;
- derive more than 60 percent of regulated operating income from gas distribution operations; and,
- were not parties to a merger or transformative transaction during the analytical periods relied on.[310]

192. Based on this screening criteria, Ms. Bulkley identified the following eight companies as the GP Proxy Group:[311]

Company	**Ticker**
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
NiSource Inc.	NI
Northwest Natural Gas Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries, Inc.	SJI
Southwest Gas Corporation	SWX
Spire, Inc.	SR

193. Both GP and the DOC-DER include Atmos Energy Corporation (Atmos), Northwest Natural Holding Company (Northwest Natural), ONE Gas, Inc. (ONE Gas), Spire Inc. (Spire), and Southwest Gas Holdings, Inc. (Southwest Holdings) in their proxy groups.[312] However, the DOC-DER specifically excluded New Jersey Resources Corporation (NJ Resources), NiSource Inc. (NiSource), and South Jersey Industries, Inc. (South Jersey) from its proxy group.[313] Both GP and the DOC-DER experts applied a Constant Growth and a Two-Growth DCF on their respective proxy groups.

5. Constant Growth vs. Two-Growth DCF Models

194. Under the Constant Growth DCF model, a company's cost of equity (k) is the sum of a stock's expected dividend yield and its expected growth rate. Estimating each proxy group member's expected growth rate (g) can be sourced from investment research services. Each company's dividend yield can be estimated using its current stock price (P), which is directly observable, it's most recent dividend (D1), which is also directly observable, and the company's expected growth rate (g), as expressed in the

[310] *Id.*
[311] *Id.* at 43.
[312] Ex. DER-1 at 13 (Addonizio Direct); Ex. GP-14 at 43 (Bulkley Direct).
[313] Ex. DER-1 at 13 (Addonizio Direct).

following equation:[314]

$$k = (D1/P) + g$$

195. Like the Constant Growth DCF model, the Two-Growth DCF model also calculates the cost of equity by using a dividend yield and a growth rate of a risk comparable company, except that the Two-Growth DCF uses a second, different growth rate after the first five years. The Two-Growth DCF accounts for situations where short-term projected growth rates may not be expected in the long-run. The Two-Growth DCF addresses these potential limitations by utilizing two different growth rates: one for the short-term and one for a longer term, sustainable growth rate.[315]

196. The Two-Growth DCF formula, as shown below, uses the short-term growth rate for the first five years, and the long-term growth rate in years six and beyond:

$$P = (D_1/(1+k)) + (D_1(1+g_1)/(1+k)^2) + (D_1(1+g_1)^2/(1+k)^3) + (D_1(1+g_1)^3/(1+k)^4) + (D_1(1+g_1)^4/(1+k)^5) + (D_1(1+g_1)^4(1+g_2)/(k-g_2)) \times 1/(1+k)^5$$

197. The first five calculations represent the dividends in years one through five, growing at the first growth rate (g_1) discounted back to the present by using the required cost of equity (k). The sixth term is the stock price in year five, estimated as the dividend in year six divided by k minus the second growth rate, and likewise discounted back to the current year.[316]

6. Great Plains DCF Analyses

198. Using the DCF equations above, Ms. Bulkley calculated the dividend yield on the GP Proxy Group companies using stock price averages for three periods in time: 30 days, 90 days, and 180 days.[317]

199. Ms. Bulkley explained that using 30-, 90-, and 180-day stock price averages: (1) ensures that the ROE is not skewed by anomalous events that may affect stock prices on any given trading day; and (2) ensures that the stock prices used are reasonably representative of expected market conditions over the long term.[318] As an example, Ms. Bulkley cited a trade dispute between the U.S. and China that caused disruption in the markets in July and August 2019.[319]

---

[314] *See Id.* at 6-7, 14; Ex. GP-14 at 52, 55-56 (Bulkley Direct).
[315] *See* Ex. DER-1 at 24-26 (Addonizio Direct).
[316] *Id.*
[317] Ex. GP-14 at 53 (Bulkley Direct).
[318] Ex. GP-16 at 32 (Bulkley Rebuttal).
[319] Ex. GP-14 at 30-31 (Bulkley Direct).

200. The results of Ms. Bulkley's Constant Growth DCF and Two-Growth DCF models for the GP Proxy Group is set forth below:[320]

	Mean Low	Mean	Mean High
Constant Growth DCF (incl. flotation cost)			
30-Day Average	8.24%	9.91%	13.69%
90-Day Average	8.32%	9.98%	13.76%
180-Day Average	8.42%	10.08%	13.86%
Two-Stage Growth DCF (incl. flotation cost)			
30-Day Average	8.13%	9.69%	12.66%
90-Day Average	8.22%	9.76%	12.73%
180-Day Average	8.31%	9.86%	12.83%

7. Department's DCF Analyses

201. Mr. Addonizio also used the Constant Growth DCF model and the Two-Growth DCF model to estimate GP's cost of equity using the DOC-DER Proxy Group.[321]

202. Mr. Addonizio determined the expected dividend yield for each company in the DOC-DER Proxy Group using its current stock price and its most recent dividend, both of which are publicly documented.[322]

203. Mr. Addonizio calculated the current stock price as the average of the closing stock price over the 30 trading days ending on December 9, 2019, a date corresponding with the timing of Mr. Addonizio's analysis.[323] Mr. Addonizio reasoned that, because share prices can be volatile in the short run, it is better to use an average share price for a period of time long enough to avoid short-term aberrations in the market, but not too long so as to no longer reflect publicly available data.[324]

204. Mr. Addonizio later updated the expected dividend yield for companies in the DOC-DER Proxy Group in his surrebuttal testimony by using the most recently available 30 trading days ending on February 12, 2020.[325]

205. For the expected dividend growth rate for each proxy company, Mr. Addonizio used the three projected earnings growth rates (lowest, average, and

---

[320] *Id.* at 65. Ms. Bulkley's results include flotation costs that she estimated at 0.10 percent (i.e., 10 basis points). *Id.* at 60.
[321] Ex. DER-1 at 23-27 (Addonizio Direct).
[322] *Id.* at 22.
[323] *Id.* at 23.
[324] *Id.*
[325] Ex. DER-9 at 35, CMA-S-6 (Addonizio Surrebuttal).

highest) provided by three investment research services: Zacks Investment Research (Zacks), Value Line, and Thomson First Call (Thomson).[326]

206. As part of this process, Mr. Addonizio performed a "high-level review" of all the projected earnings growth rates to identify any unreasonably high or low values.[327] Mr. Addonizio identified one unreasonable growth rate: Value Line's 27 percent five-year growth rate for Northwest Natural.[328] Mr. Addonizio concluded that Value Line's 27 percent growth rate was inappropriate to include in the DCF analyses because it was more than five times higher than the other two estimates for Northwest Natural and three times higher than the next highest single estimate for any of the other proxy companies.[329]

207. Upon further investigation, Mr. Addonizio determined that Northwest Natural's earnings growth estimate was caused by its decision to "write off" a poorly performing asset in 2017, coupled with stable earnings in 2016, 2017, and 2018.[330] Mr. Addonizio explained that the other earnings growth rates for Northwest Natural (provided by Zachs and Thomson) appear to account for this balance sheet change, and provide a more accurate estimate of the company's future earnings (5.00 percent and 3.75 percent, respectively).[331]

208. Mr. Addonizio also addressed Spire's estimated earnings growth rate. Mr. Addonizio concluded that any concerns regarding Yahoo!'s estimated earnings for the company were mooted by a subsequent upwards adjustment.[332]

209. Mr. Addonizio next performed a Two-Growth DCF analysis for each company. For the short-term growth rate, Mr. Addonizio used the five-year projected earnings growth rates that he used in the Constant Growth DCF analysis from Zacks, Value Line, and Thomson.[333]

210. For the long-term growth rates, Mr. Addonizio first determined the likelihood for each company in the DOC-DER Proxy Group that its five-year projected growth rate is sustainable. According to Mr. Addonizio, growth rates may be considered "unsustainable" if they are unusually low or unusually high relative to the industry.[334]

---

[326] Ex. DER-1 at 14-15 (Addonizio Direct).
[327] Ex. DER-9 at 30 (Addonizio Surrebuttal).
[328] *Id.* at 31.
[329] *Id*.
[330] DER-1 at 18-20 (Addonizio Direct).
[331] *Id*. at 21-22 ("Zacks and Thomson reported expected earnings growth rates of 5.00 percent and 3.75 percent, respectively. . . . [I]t seems clear that both Zacks and Thomson removed the impact of [Northwest Natural's] write down of the Gill Ranch Facility from their forecasts.").
[332] Ex. DER-9 at 35 (Addonizio Surrebuttal).
[333] DER-1 at 26 (Addonizio Direct).
[334] *Id.* at 26-27.

211. To make this assessment, Mr. Addonizio calculated the average growth rate for the DOC-DER Proxy Group and the standard deviation of the growth estimates. He determined that any growth rate that was lower than one standard deviation below the proxy group's average may not be sustainable and, similarly, any growth rate that is higher than one standard deviation above the proxy group's average growth rate may not be sustainable.[335]

212. As part of his Two-Growth DCF analyses, Mr. Addonizio again performed a "high-level review" of his inputs. While the two-growth DCF model is intended to mitigate the effect of unsustainable growth rates, it is not robust against extreme outliers. According to Mr. Addonizio, Value Line's 27 percent growth estimate would have unreasonably inflated the group's average and its standard deviation, resulting in a much higher and much wider range of ROEs considered to be sustainable.[336] Inclusion of Value Line's 27 percent growth estimate would have dramatically increased the recommended ROE for GP from 8.82 percent to 10.26 percent, before adjusting for flotation costs.[337]

213. In sum, Mr. Addonizio's initial DCF results were as follows:[338]

Summary of DOC-DER's DCF Initial Results
(Adjusted for Flotation Costs)

Model	Mean Low ROE	Mean Avg. ROE	Mean High ROE
Constant Growth DCF	8.03%	8.95%	9.75%
Two-Growth DCF	8.04%	8.87%	9.75%

214. In February 2020, after filing his direct testimony, Mr. Addonizio reconfirmed that all of the DOC-DER Proxy Group companies continued to meet his eligibility criteria.[339] He then updated the stock prices he used when calculating dividend yields and the dividend amounts for companies that changed their dividends since his first analysis.[340] Mr. Addonizio also updated the growth estimates for some of the companies in the DER-DOC Proxy Group based on new data from Zacks and Thomson. (Value Line did not release new information after his first analysis so information from Value Line did not change).[341]

[335] *Id.*
[336] *Id.* at 28.
[337] *Id.*
[338] *Id*. at 33.
[339] Ex. DER-9 at 3 (Addonizio Surrebuttal).
[340] *Id*.
[341] *Id*. at 3-4.

215. Mr. Addonizio's updated analyses relied on the 30-day average stock prices ending February 13, 2020, which was near the highest point in the Dow Jones Industrial Average.[342] Since that time, the market has experienced tremendous volatility due to a U.S. trade dispute with China and panic associated with a worldwide pandemic (COVID-19).[343]

216. Based on this updated information, Mr. Addonizio completed a revised and final DCF analysis for the DOC-DER Proxy Group, as follows:[344]

Summary of DOC-DER's Final DCF Results
(Adjusted for Flotation Cost)

Model	Mean Low ROE	Mean Avg. ROE	Mean High ROE
Constant Growth DCF	7.95%	8.79%	9.67%
Two-Growth DCF	7.90%	8.82%	9.67%

Ex. DER-9, CMA-S-2 through CMA-S-5 (Addonizio Surrebuttal)

217. Mr. Addonizio noted that the mean average ROE from his Constant Growth DCF and the Two-Growth DCF were now lower than in its initial analysis, going from 8.95 percent in the Constant Growth DCF to 8.79 percent; and from 8.87 percent in the Two-Growth DCF to 8.82 percent.[345]

218. From the ranges identified in the updated DCF, Mr. Addonizio recommended a final ROE of 8.82 percent, including his flotation adjustment discussed below.[346]

8. Application of "Checks" on DCF Analyses

219. Both Ms. Bulkley and Mr. Addonizio used other analytical tools to perform "checks" on the results they obtained from their respective DCF models. Mr. Addonizio used only the Capital Asset Pricing Model (CAPM).[347] Ms. Bulkley used the CAPM, the Bond Yield Plus Risk Premium, and the Expected Earnings methods for comparing her DCF results.[348]

---

[342] Ex. GP-17 at 3 (Bulkley Summary).
[343] *Id.*
[344] Ex. DER-9 at 4 (Addonizio Surrebuttal).
[345] *Id.*
[346] Ex. DER-16 (Addonizio Summary).
[347] *Id.*
[348] Ex. GP-14 at 110 (Bulkley Direct).

220. CAPM's basic premise is that any company-specific risk can be diversified away by investors. Therefore, under this theory, the only risk that matters is the stock's systematic risk, which is measured by a beta (a market risk premium).[349] The required rate of return on the stock is calculated as the sum of the stock's beta, multiplied by the market risk premium and the rate of return on a "riskless" asset.[350] It is expressed in the following formula:[351]

$$k = r_f + \text{beta}\,(r_m - r_f)$$

k is the required rate of return
r_f is the rate of return on a riskless asset
r_m is the market rate of return
$(r_m - r_f)$ is the market risk premium

a. Department CAPM Analysis

221. Using the CAPM method and formula, Mr. Addonizio conducted an analysis to determine if his DCF results were similar results obtained by CAPM.

222. The first input into the CAPM formula is the rate of return on a riskless asset (r_f). A 30-year U.S. Treasury bond is generally considered to be devoid of default risk.[352] However, when applying the CAPM analysis, Mr. Addonizio used for the (r_f) the rate of return on a 20-year U.S. Treasury bond, as opposed to a 30-year bond.[353] According to Mr. Addonizio, a 20-year bond better approximates an equity investor's stock holding period (when compared to a 90-day bond), and requires less time for an investor to be "tied up" in the investment (when compared to a 30-year Treasury bond).[354] Additionally, he used the average yield over the last 30 trading days prior to his analysis to eliminate any bias from day-to-day volatility.[355]

223. The second input into the CAPM formula is the market rate of return (r_m). To determine the market rate of return, it is necessary to select a market portfolio. [356] Once a market portfolio is selected, the required return on that portfolio can be estimated.[357] In this case, Mr. Addonizio used the S&P 500, a common choice for CAPM analyses, as a proxy for the market portfolio.[358] State Street Global Advisors manages an exchange-traded fund (ETF) designed to mimic the S&P 500 Index, and reports an estimated 3-to-5-year earnings growth rate for the holdings of the ETF that it

[349] Ex. DER-1 at 33-34 (Addonizio Direct).
[350] *Id.*
[351] Ex. GP-14 at 66 (Bulkley Direct).
[352] *Id.* at 67; Ex. DER-16 at 35 (Addonizio Direct).
[353] Ex. DER-16 at 35-36 (Addonizio Direct).
[354] *Id.*
[355] *Id.* at 36.
[356] *Id.* at 36-37.
[357] *Id.*
[358] *Id.*

calculates using equity analysts' earnings estimates for the companies included in the ETF.[359] Mr. Addonizio used this earnings growth estimate as the estimate of the growth rate for the market portfolio, which was 10.75 percent as of January 1, 2020.[360]

224. The CAPM also requires the calculation of a dividend yield. According to Mr. Addonizio, the dividend yield for the S&P 500 as of January 1, 2020, was 1.77 percent.[361] Similar to the dividend yields used in his DCF analysis, Mr. Addonizio applied a half years' worth of growth to this dividend yield, resulting in a dividend yield of 1.87 percent.[362] Thus, Mr. Addonizio determined that the required rate of return on the S&P 500 is 1.87 percent + 10.73 percent = 12.62 percent.[363] Mr. Addonizio used this return as the market rate of return (r_m).[364]

225. The third input into the CAPM formula is the estimated "beta" for the target company. The beta is a measure of the volatility – or systematic risk – of a security or portfolio compared to the market as a whole.

226. Mr. Addonizio relied on the beta estimate provided by Value Line for each of the companies in the DOC-DER Proxy Group.[365] An average of these betas produced a beta figure of 0.64.[366]

227. Using the CAPM formula described above, Mr. Addonizio initially calculated GP's required rate of return as 8.90 percent, including a flotation cost adjustment of five basis points (flotation costs are discussed, in detail, later in this Report).[367] This CAPM result fell within the range of Mr. Addonizio's initial DCF results (8.03 to 9.75 percent) and was nearly identical to his initial Two-Growth DCF result (8.95 percent).[368] Consequently, Mr. Addonizio determined that his initial DCF results were reliable and recommended a ROE of **8.87 percent** based upon a mean ROE of 8.82 percent plus five basis points for flotation costs.[369]

228. However, as set forth above, as part of his rebuttal analysis, Mr. Addonizio updated his CAPM analyses with more current estimates of the risk-free rate and the rate of return on the market portfolio.[370] With this new data, Mr. Addonizio re-ran his CAPM analysis against his final DCF results.[371] His updated CAPM analysis resulted in

---

359 *Id.*
360 *Id*.
361 *Id*.
362 *Id*.
363 *Id*.
364 *Id.* at 37.
365 *Id.*
366 *Id.*
367 *Id*.
368 *Id*. at 38.
369 *Id*.
370 Ex. DER-9 at 4-5 (Addonizio Surrebuttal).
371 *Id*.

an estimated ROE of **9.38 percent**, including flotation costs of five points.[372] This result, too, falls within the ROE range Mr. Addonizio developed with his final DCF analysis (7.90 to 9.67 percent), however it is **56 basis points higher** than his final DCF recommended ROE of 8.82 percent.[373]

229. Nonetheless, based upon his CAPM analysis, Mr. Addonizio concluded that his DCF results were reasonable because the CAPM result fell within the mean high and mean low range of this final DCF.[374] Despite the CAPM being significantly higher than his final DCF mean recommendation, Mr. Addonizio's final ROE recommendation continues to be **8.82 percent**, based upon his final Two Growth DCF analysis.[375]

a. Great Plains' CAPM, Bond Yield Risk Premium Analysis, and Expected Earnings Analysis

231. Ms. Bulkley conducted three "checks" on her DCF results. She conducted a CAPM, a Bond Yield Risk Premium analysis, and an Expected Earnings analysis.

232. In her CAPM, Ms. Bulkley relied on three sources for the rate of return on a riskless asset (r_f): (1) the 30-day average yield on 30-year U.S. Treasury bonds (2.57 percent); (2) the average projected 30-year U.S. Treasury bond yield for Q4 2019 through Q4 2020 (2.66 percent); and (3) the average projected 30-year U.S. Treasury bond yield for 2021 through 2025 (3.6 percent).[376] She placed most weight on the projected yields of the 30-year Treasury bond.[377] In other words, Ms. Bulkley relied upon forecasted yields to determine the risk-free rate, as opposed to the known 30-year U.S. Treasury bond rate.[378]

233. Ms. Bulkley then used the beta coefficients for the GP Proxy Group companies as reported by Bloomberg and Value Line, and selected a 10-year period to calculate the beta coefficients from Bloomberg.[379]

234. Ms. Bulkley estimated the market risk premium based on the expected return on S&P 500 Index, less the yield premium on the 30-year Treasury Bond.[380] Using the DCF model, she calculated the expected return on the S&P 500 Index companies for which dividend yields and long-term earnings projections were available.[381] Based on an estimated market capitalization-weighted dividend yield of

---

372 *Id*.
373 *Id.*
374 *Id.*
375 Ex. DER-16 (Addonizio Summary).
376 Ex. GP-14 at 67 (Bulkley Direct).
377 *Id*.
378 *Id*. at 66-67.
379 *Id*. at 68.
380 *Id*. at 70.
381 *Id*.

1.94 percent and a weighted long-term growth rate of 11.84 percent, she determined that the estimated market return for the S&P 500 Index was 13.90 percent.[382]

235. Mr. Addonizio reviewed Ms. Bulkley's estimate of the required market return and choice of beta, and concluded that it appeared reasonable.[383]

236. Ms. Bulkley's CAPM analysis produced a range of returns from 10.08 percent to 10.84 percent, as set forth below:[384]

Great Plains' CAPM Results

	Bloomberg Beta	**Value Line Beta**
Current Risk-Free Rate (2.57%)	10.53%	10.08%
Q4 2019-Q4 2020 Projected Risk-Free Rate (2.66%)	10.56%	10.11%
2021-2025 Projected Risk-Free Rate (3.60%)	10.84%	10.43%
Mean Result	**10.64%**	**10.20%**

237. Mr. Addonizio noted that Ms. Bulkley's CAPM analyses produced a required market return estimate of 13.90 percent, in contrast to Mr. Addonizio's own estimate of 12.92 percent, even though both experts used similar approaches and relied on respected datasets.[385]

238. Ms. Bulkley next conducted a Bond Yield Plus Risk Premium analysis.[386] This approach is based on the principle that equity investors bear the residual risk associated with equity ownership and, therefore, require a premium over the return they would have earned as a bondholder.[387] In other words, because returns to equity holders have greater risks than returns to bondholders, equity investors should be compensated for that risk.[388] The risk premium approach, thus, estimates the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds.[389]

239. To conduct this approach, Ms. Bulkley used historical data going back to 1992 to estimate the historical relationship between the equity risk premium for gas utilities and the yield on 30-year U.S. Treasuries.[390] She then derived an estimate of the

382 *Id*.
383 *Id*. at 68-69.
384 *Id*. at 73.
385 Ex. DER-1 at 57-58 (Addonizio Direct).
386 Ex. GP-14 at 73-77 (Bulkley Direct).
387 *Id*. at 73.
388 *Id*.
389 *Id*.
390 *Id*. at 73-77.

current equity risk premium by applying that historical relationship to current 30-year Treasury yields, as well as two forecasts of 30-year Treasury yields.[391]

240. Ms. Bulkley's Bond Yield Plus Risk Premium resulted as follows:[392]

GP's Bond Yield Plus Risk Premium Results

	Risk Premium	Estimated ROE
Current Risk-Free Rate (2.57%)	6.97%	9.53%
Q4 2019-Q4 2020 Projected Risk-Free Rate (2.66%)	6.91%	9.57%
2021-2025 Projected Risk-Free Rate (3.60%)	6.39%	9.99%

241. Finally, Ms. Bulkley conducted an Expected Earnings analysis.[393] An Expected Earnings methodology is a comparable earnings analysis that calculates the earnings that an investor expects to receive on the book value of a stock.[394] The use of this approach, based on the GP's proxy companies, provided a range of expected returns on the proxy groups companies, which is then translated to GP.[395]

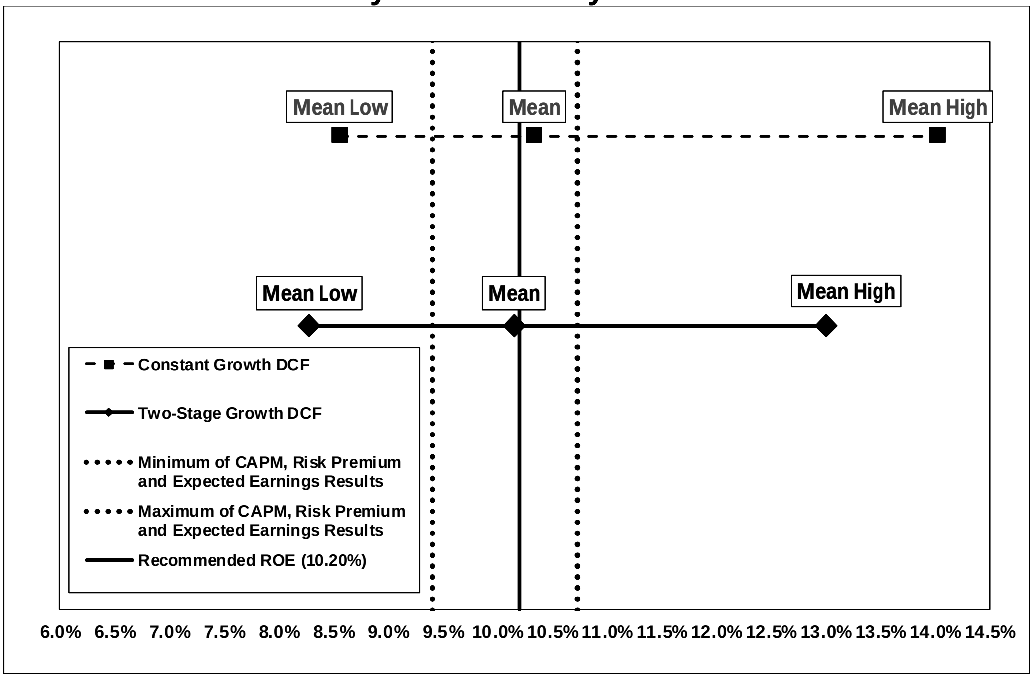
242. In her analysis, Ms. Bulkley relied primarily on the projected ROE capital for the proxy companies as reported by Value Line for the period from 2022 to 2024.[396] The projected ROEs were then adjusted to account for the fact that the ROEs reported by Value Line are calculated on the basis of common shares outstanding at the end of the period, as opposed to average shares outstanding over the period.[397]

243. Ms. Bulkley's Expected Earnings Approach resulted in a mean ROE of 10.90 percent and a median ROE of 10.59 percent.[398]

244. Ms. Bulkley then compared her DCF results with the other three analytical approaches in the following table:[399]

[391] *Id*.
[392] *Id*. at 76.
[393] *Id*. at 77-79.
[394] *Id*. at 77.
[395] *Id*.
[396] *Id*. at 79.
[397] *Id*.
[398] *Id*.
[399] Ex. GP-16 at 8 (Bulkley Rebuttal).

Summary of GP's Analytical Results



c. GP's Qualitative Analysis

245. In addition to the DCF, CAPM, Bond Yield Risk Premium method, and Expected Earnings analysis, Ms. Bulkley considered certain qualitative risk factors to reach a final ROE from the range of ROE result set forth in the table above. Specifically, Ms. Bulkley considered GP's business and financial risk relative to the companies in her proxy group.[400] Ms. Bulkley refers to this analysis as reviewing GP's "risk profile."[401]

246. While Ms. Bulkley did not articulate specific adjustment to her recommended ROE for GP based on these factors, she considered them in aggregate in determining where, within the range of results, the authorized ROE for GP should be set.[402]

247. Specifically, Ms. Bulkley considered GP's size, customer concentration, capital expenditures, and regulatory environment when reaching her final ROE decision.[403] Based on these risk factors, Ms. Bulkley made an upward adjustment to recommend a final ROE of 10.2 percent.[404]

---

[400] Ex. GP-14 at 5-7 (Bulkley Direct).
[401] *Id*. at 80-97.
[402] Ex. GP-16 at 68-69 (Bulkley Rebuttal).
[403] Ex. GP-14 at 80-106 (Bulkley Direct).
[404] Ex. GP-17 at 14 (Bulkley Summary).

248. First, Ms. Bulkley asserts that GP is riskier than the proxy group companies because of its small size.[405] GP serves approximately 22,000 customers and had net plant capital expenditures of approximately $30.6 million in 2018.[406] As a result, its operations were substantially smaller than the median for the proxy group companies in terms of market capitalization.[407]

249. Citing scholarly work, Ms. Bulkley explained that small utilities, like GP, face obstacles that larger utilities do not face, including a smaller customer base, limited financial resources, and a lack of diversification of customers, energy sources, and geography.[408] As a result, a smaller utility is less able to withstand adverse events that affect its revenue and expenses, such as weather variability, the loss of a large customer, or reduced demand.[409] In addition, capital expenditures can have a greater proportional effect on customers.[410] As a result of these risks, Ms. Bulkley argues that small utility investors expect a higher return on their investment to justify the additional risks.[411] Based upon its small size, Ms. Bulkley asserts that the Commission should approve a ROE above the mean results for the proxy group.[412]

250. Second, Ms. Bulkley concluded that GP is subject to greater risk than other companies in her proxy group because of its reliance on commercial and industrial customers.[413] Located in western Minnesota, most of GP's industrial customers are in the agricultural industry.[414] Approximately 60.94 percent of its 2017 deliveries were derived from industrial customers, with the majority of those based or related to agriculture or ethanol production.[415] Compared to the GP Proxy Group, GP's commercial and industrial gas deliveries totaled 82.90 percent of its business, which was higher than all of the companies in the proxy group.[416] Indeed, 60.94 percent of its total gas deliveries in Minnesota were to industrial customers.[417]

251. The extremely high concentration of industrial customers results in higher business risks for GP.[418] Because industrial/agricultural customers are large, they can present a significant part of GP's business.[419] Should such a customer go out of business, it could have a significant impact on GP's overall business.[420]

---

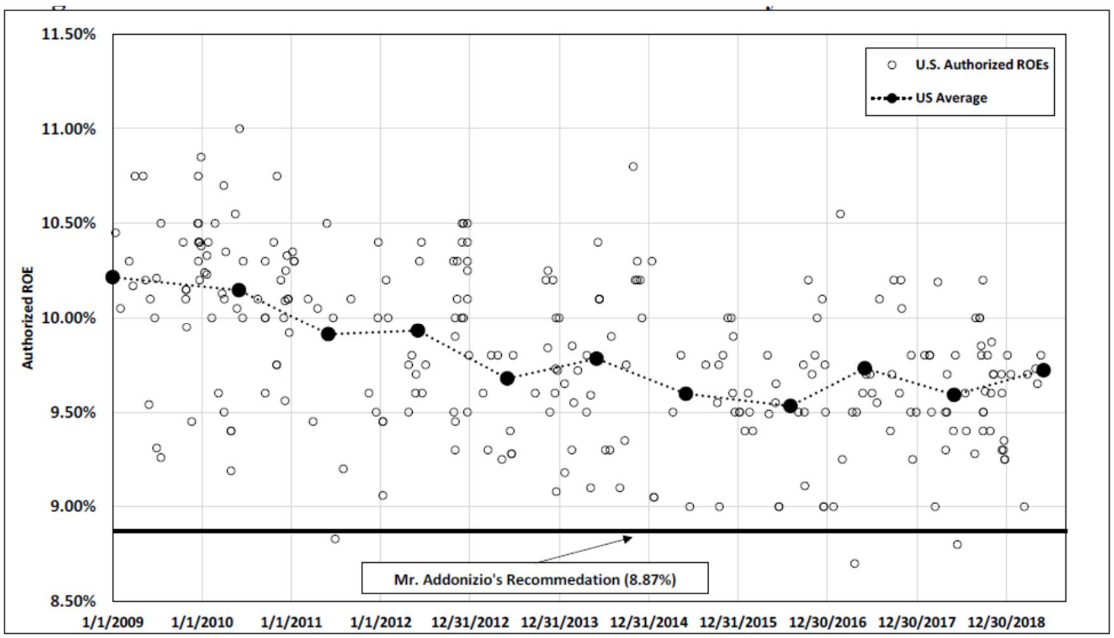
[405] Ex. GP-14 at 80-85 (Bulkley Direct).
[406] *Id*. at 81.
[407] *Id*.
[408] *Id*. at 80.
[409] *Id.*
[410] *Id*. at 81.
[411] *Id*. at 80.
[412] *Id*. at 85.
[413] *Id*. at 85-87.
[414] *Id*. at 85.
[415] *Id*.
[416] *Id*. at 85-86.
[417] *Id*. at 92.
[418] *Id*. at 86-87, 92-93.
[419] *Id*. at 86-87.
[420] *Id*.

252. GP's major industrial customers are engaged in industries such as grain drying/storage, sugar beet processing, ethanol production, and other agricultural processes.[421] Commodity price volatility and trade disputes have a direct impact on these customers.[422] These national and international economic conditions could, therefore, have an appreciable impact on GP's business should these industrial customers reduce consumption due to negative economic conditions.[423]

253. A high degree of customer concentration increases GP's risk related to customer migration, changes in economic conditions, and competition.[424] This risk is even higher in GP's service territory because the residential and commercial customers rely on the success of the industrial customers in the area for sales and employment.[425]

254. Finally, Ms. Bulkley considered the DOC-DER's recommended ROE (8.82 percent) against the authorized returns for natural gas utilities in other jurisdictions since January 2009, as well as the returns authorized in Minnesota for natural gas companies. The chart below summarizes her findings:[426]

Comparison of Minnesota and U.S. Authorized Natural Gas Returns



---

[421] *Id*. at 87.
[422] *Id*. at 87-88.
[423] *Id*.
[424] *Id*. at 92-93.
[425] *Id*.
[426] Ex. GP-17 at 7 (Bulkley Summary).

255. According to Ms. Bulkley, from 2009 through 2011, the Commission's authorized ROEs were at or near the average authorized return on equity for the U.S.[427] However, beginning in 2012 through 2016, the Commission's authorized ROEs were below the U.S. average.[428] Ms. Bulkley opined that this may be the result of the Commission's reliance on the DCF as a method for determining ROE.[429] Ms. Bulkley noted that the Commission recently authorized a ROE of 9.70 percent for MERC in Docket No. G011/GR-17-563, which was consistent with the national average for natural gas companies in the U.S.[430] According to Ms. Bulkley, the result in MERC was the result of the Commission relying on the Two-Growth DCF, other analytical approaches, and other contextual data, and not just the DCF.[431]

256. Mr. Addonizio's final recommended ROE of 8.82 percent is at the very low end of the range of authorized ROEs and well below the average annual authorized ROE for natural gas utilities from 2009 through 2019.[432] In fact, it is less than all but two other authorized ROEs for natural gas utilities between 2009 and 2019.[433]

257. Ms. Bulkley opined that, based upon her DCF and other analyses, and in recognition of the Company's small size, its heavy reliance on a small number of industrial customers, and its need to compete for capital, a reasonable ROE in this case should be in the range 9.75 and 10.25 percent.[434] From this range, she ultimately recommended a ROE of 10.2 percent ROE for GP.[435]

9. Analysis of the Administrative Law Judge

a. The Department's DCF Analysis is More Reliable

258. The Administrative Law Judge finds that the DCF conducted by the DOC-DER is more reliable than that presented by the Company.

259. First, the proxy group of companies selected by Ms. Bulkley contained two companies that were properly excluded by the DOC-DER for failing to meet the 60-percent operating income from natural gas distribution threshold: South Jersey and NiSource.[436] The record establishes that, due to losses in the non-regulated segments of these business, the operating income for the regulated segments of these companies appear disproportionately large.[437] To counteract this distortion, the DOC-DER

[427] Ex. GP-14 at 94 (Bulkley Direct).
[428] *Id*.
[429] *Id*.
[430] *Id*. at 95.
[431] *Id*.
[432] Ex. GP-16 at 11-12 (Bulkley Rebuttal).
[433] *Id*.
[434] *Id*. at 8-9.
[435] *Id*.
[436] DER-1 at 11-12 (Addonizio Direct).
[437] *Id.* at 45-46.

recommended that GP use the absolute values of each segment's operating income or loss to calculate the total company amount, as well as the percentages attributable to each segment, to avoid this distortion.[438] Applying this adjustment, these two companies would be excluded as not meeting the required 60 percent operating income threshold, which was applied by both Mr. Addonizio and Ms. Bulkley.[439]

260. While Ms. Bulkley argued that these losses were due to one-time events for these companies,[440] it is speculative to conclude that South Jersey and NiSource would exceed the 60 percent income threshold in the future. This is particularly true given that: (1) South Jersey's share of operating income from regulated operations had decreased even in the absence of the impairments cited by Ms. Bulkley as one-time events;[441] and (2) significant uncertainty continues to surround NiSource following the natural gas explosion.[442] Moreover, the relevant question for determining suitability for inclusion in a proxy group is not whether the companies are likely to exceed the income threshold in the future, but rather whether the companies meet the income screens articulated by the analysts at the time of the analysis.[443] Accordingly, both of these companies were properly excluded from the proxy group.

261. Second, Ms. Bulkley included NJ Resources in GP's Proxy Group despite its questionable creditworthiness. The S&P withdrew all of its credit ratings for NJ Resources on May 24, 2019.[444] While its utility subsidiary, New Jersey Natural Gas, does have an investment-grade credit rating from Moody's,[445] this rating is insufficient because it was not an issuer-level credit rating and is not directly applicable to NJ Resources.[446] Issuer-level credit ratings are based on an entity's ability to "honor senior unsecured debt and debt like obligations."[447] In contrast, Moody's investment grade credit rating for New Jersey Natural Gas is based on its ability to pay secured debt.[448] Secured debt is less risky than unsecured debt and results in higher credit ratings, thereby overstating the subsidiary's creditworthiness.[449] Moreover, it is unclear in the record whether the Moody's rating applied beyond a specific debt issuance by New Jersey Natural Gas made in conjunction with the New Jersey Economic Development Authority.[450] Therefore, GP has failed to establish that NJ Resources met its own screen of having a "long-term issuer rating."[451]

---

[438] *Id.* at 47; Ex. GP-14 at 43 (Bulkley Direct).
[439] Ex. DER-1 at 47-48 (Addonizio Direct).
[440] Ex. GP-16 at 19-25 (Bulkley Rebuttal).
[441] Ex. DER-9 at 9 (Addonizio Surrebuttal).
[442] *Id.* at 11-12; Ex. DER-1 at 50 (Addonizio Direct);
[443] Ex. DER-1 at 50 (Addonizio Direct); Ex. DER-9 at 9-10 (Addonizio Surrebuttal).
[444] Ex. DER-1 at 50 (Addonizio Direct).
[445] Ex. GP-16 at 27-28 (Bulkley Rebuttal); Ex. DER-9 at 21-22 (Addonizio Surrebuttal).
[446] Ex. DER-9 at 22 (Addonizio Surrebuttal).
[447] *Id.* at 23 (quoting MOODY'S INVESTOR SERVICE, RATING SYMBOLS AND DEFINITIONS 9 (2020), available at https://perma.cc/FB7Z-Z866).
[448] *Id*. at 23-24, CMA-S-19 at 2.
[449] *Id*. at 25.
[450] *Id.* at 25-26.
[451] *Id*.

262. Third, unlike Mr. Addonizio, Ms. Bulkley used Value Line's 27 percent growth rate for Northwest Natural as part of her DCF analyses.[452] Value Line's 27 percent earnings growth rate is five times higher than any other estimate for Northwest Natural and three times higher than the next highest single estimate for any other proxy company.[453] As explained by Mr. Addonizio, this earnings growth estimate was caused by Northwest Natural's decision to write off a poorly performing asset in 2017, coupled with stable earnings in 2016, 2017, and 2018.[454] As a result of this write-off, Value Line's 27 percent growth rate is inflated, is unrepresentative of Value Line's assessment of Northwest Natural's expected earnings growth, and is not suitable for use in a DCF analysis.

263. In sum, the inclusion of South Jersey, NiSource, and NJ Resources in GP's Proxy Group, as well as the use of an inflated earnings growth rate for Northwest Natural, render Ms. Bulkley's DCF analyses less reliable than the DCF analysis performed by the Department. The Administrative Law Judge, therefore, recommends that the Commission rely on the range of DCF results supplied by the DOC-DER over those presented by GP.

b. CAPM and Other Methodologies Used to "Check" DCF Results

264. The Administrative Law Judge also finds that the Department's CAPM analysis is more reliable than the CAPM performed by GP. The DOC-DER's CAPM analysis used the established 20-year Treasury bond yield.[455] Whereas, Ms. Bulkley relied mostly on forecasted (verses established) bond yields to determine the risk-free rate.[456]

265. Long-term interest rates, including yields on Treasury bonds, are determined by market forces.[457] In this way, current bond yields reflect investor expectations about future economic and financial conditions.[458] Because current bond yields reflect expected future developments, any changes to bond yields in the future will necessarily reflect the predictions that cause investors to adjust their expectations.[459] Forecasted bond yields suffer from the uncertainty that they are attempting to predict unanticipated future events.[460] If these future developments were anticipated, then current bond yields would already reflect these anticipated changes.[461]

452 *Id.* at 30-31, Figure 5.
453 *Id.* at 31.
454 Ex. DER-1 at 18 (Addonizio Direct).
455 *Id*. at 35-36.
456 Ex. GP-14 at 66-67 (Bulkley Direct).
457 Ex. DER-1 at 56 (Addonizio Direct).
458 *Id*.
459 *Id*.
460 *Id*.
461 *Id*.

Accordingly, the ALJ finds that long-term forecasted bond yields are subject to too much uncertainty and the ROE estimates produced with them are thus less reliable than a CAPM using established rates.[462]

266. The Administrative Law Judge concurs with Mr. Addonizio that the Bond Yield Plus Risk Premium analysis used by GP is not as sound of a method of determining ROE than the DCF or CAPM because it is backward looking, rather than forward-looking.[463] The Bond Yield model assumes that the relationship between the equity risk premium for gas distribution utilities and treasury yields does not depend on investors adjusting their expectations depending on different economic and financial conditions, such as changing federal monetary and fiscal policies.[464]

267. In addition, Ms. Bulkley used forecasted interest rates in her Bond Yield Plus Risk Premium analysis, like she did in her CAPM.[465] As set forth above, these forecasted interest rates are subject to more uncertainty and are, thus, inferior to current interest rates as predictors of future interest rates. [466] Accordingly, the Administrative Law Judge gave little weight to the results of GP's Bond Yield Plus Risk Premium analysis.

268. The Administrative Law Judge also gives little weight to the Expected Earnings methodology used by GP to estimate ROE. The Expected Earnings methodology is an accounting-based methodology, not a market-based one.[467] It estimates a rate of return on the book value of a company's equity.[468] However, investors cannot purchase shares of common stock at their book value.[469] Investors must pay the current market value for shares.[470]

269. The Federal Energy Regulatory Commission (FERC) has recently determined that the Expected Earnings Methodology is inappropriate for determining ROE.[471] FERC explained, "The Expected Earnings methodology provides an accounting-based approach that uses investment analyst estimates of return . . . on book value[.]"[472] FERC concluded:

> In particular, we find that the record does not support departing from our traditional use of market-based approaches to determine

[462] *Id.* at 56-57.
[463] Ex. GP-14 at 73-77 (Bulkley Direct).
[464] Ex. DER-1 at 59 (Addonizio Direct).
[465] Ex. GP-14 at 76 (Bulkley Direct).
[466] Ex. DER-1 at 60-61 (Addonizio Direct).
[467] *Id*.
[468] *Id*.
[469] *Id*.
[470] *Id*.
[471] Opinion No. 569, *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. System Operator, Inc.*, 169 F.E.R.C. ¶ 61,129, 61,301 (slip op., para. 172) (2019), available at www.ferc.gov/whats-new/comm-meet/2019/112119/E-11.pdf.
[472] *Id*.

> base ROE. Under the market-based approach, the Commission sets a utility's ROE to equal the estimated return that investors would require in order to purchase stock in the utility at its current market price. In *Hope*, the Supreme Court explained that "the return to te equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."
>
> . . . .
>
> The return on book value is also not indicative of what return an investor requires to invest in the utility's equity or what return an investor receives on the equity investment, because those returns are determined with respect to the current market price that an investor must pay in order to invest in the equity.[473]

270. In this way, FERC reasoned that it would be illogical to set ROE based on book value when actual equity investment must be made at the company's current market price. For these same reasons, the Administrative Law Judge gives the Expected Earnings analysis little weight.

271. In sum, the Administrative Law Judge gives significant weight to the DOC-DER's CAPM results of **9.38 percent**. This amount is squarely within the range of DCF results in both Mr. Addonizio's initial and final DCF analyses (ranging from 8.03-9.75 percent and 7.90 – 9.67 percent, respectively), falling closing to the high mean range.

272. It is also more consistent with Ms. Bulkley's application of Mr. Addonizio's DCF analysis when applied to GP's Proxy Group (which included the three companies excluded by Mr. Addonizio). Using Mr. Addonizio's methodology for DCF, but applied to GP's larger proxy group, would result in a Two-Growth DCF mean result of **9.47 percent** before the application of flotation costs, and **9.52 percent** after the addition of Mr. Addonizio's recommended flotation costs of five points.[474]

273. When using the GP Proxy Group and adjusting the Value Line earning growth rate for Northwest Natural, as recommended by Mr. Addonizio, the mean Two-Growth DCF is **9.58 percent** before the addition of flotation costs, and **9.63 percent** after the addition of five basis points flotation costs.[475] In other words, applying Mr. Addonizio's methodology to GP's Proxy Group nets results closer to Mr. Addonizio's CAPM than his own Two-Growth DCF results for the DOC-DER Proxy Group.

---

[473] *Id.* at ¶ 61,329-330 (slip op., paras. 200-201) (citing *Fed. Power Comm'n, vs. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944)).

[474] Ex. GP-16 at 30-31 (Bulkley Surrebuttal). With the addition of 5 basis points for flotation costs, the ROE would be 9.52 percent. *Id.* at 48.

[475] *Id*. at 43, 48.

c. Qualitative Risks and National ROEs Support an Upward Adjustment in ROE

274. In addition to her DCF, CAPM, and other quantitative analyses, Ms. Bulkley undertook a qualitative review to determine a final ROE within the range of ROE results indicated in her mathematical analyses. She described this as reviewing GP's "risk profile."[476] Specifically, Ms. Bulkley considered GP's small size, its customer concentration, capital expenditures, and regulatory environment when reaching her final ROE decision from the range of results presented in her quantitative analysis.[477] Mr. Addonizio did not engage in this type of additional analysis and simply selected the mean ROE from his Two-Stage DCF equation.

275. When deciding on a ROE within a range identified by the quantitative methods described herein (DCF, CAPM, etc.), is reasonable to look to qualitative factors that may justify an upward or downward departure from the mean quantitative results. For example, a company with a history of service issues or financial mismanagement should not be rewarded with an upward departure of ROE from that suggested by the quantitative economic analyses. At the same time, companies that face additional obstacles or risks from their publicly-traded proxy group counterparts may be entitled to an upward departure to ensure that they are able to raise capital in the competitive market, in light of such additional risks. There are some risks or factors that are simply not captured by a mathematical equation or quantitative analysis. This is particularly true when comparing a small, non-publicly traded company to a large, publicly-traded company.

276. The record in this proceeding shows that Great Plains is, in fact, significantly smaller than the publicly-traded proxy companies used in the experts' DCF analyses. Unlike large, publicly-traded companies, small utilities are less able to withstand adverse events that affect their revenue and expenses, such as weather variability, the loss of a large customer, or reduced demand.[478]

277. In addition, GP has risk related to the concentration of industrial customers in its service territory focused on agriculture or the production of ethanol.[479] Located in western Minnesota, GP is highly dependent upon its industrial/agricultural customer base, which represents 60.94 percent its 2017 deliveries.[480] Its residential and commercial customers are also dependent on that same industrial base.[481] Consequently, economic events that impact these agricultural and ethanol producers inevitably impact GP's entire customer base.[482]

[476] Ex. GP-14 at 80-97 (Bulkley Direct).
[477] *Id*. at 80-106.
[478] *Id*. at 81.
[479] *Id*. at 80-89; Ex. GP-16 at 68-71 (Bulkley Rebuttal); Ex. GP-17 at 2 (Bulkley Summary).
[480] Ex. GP-14 at 85 (Bulkley Direct).
[481] *Id*. at 86.
[482] *Id*.

278. The Commission recently determined that it is necessary to account for differences in investment risk between the proxy group and the utility for which the return is being set. In its May 2017 Order addressing Otter Tail Power Company's ROE, the Commission found that the higher business risks faced by Otter Tail (which included small size, equity price volatility, low institutional ownership, and trading volume), relative to the proxy group companies, supported a return above the mean DCF results.[483] The Commission stated:

> The record in this case establishes a compelling basis for selecting an ROE above the mean average within the DCF range, given Otter Tail's unique characteristics and circumstances relative to other utilities in the proxy group. These factors include the company's relatively smaller size, geographically diffuse customer base, and the scope of the Company's planned infrastructure investments. The Commission has also considered Otter Tail's recognized [sic] the Company's performance in completing major infrastructure projects substantially under budget, its history of providing reliable service with stable rates, and its record of effectively serving the needs of its customers, as measured by multiple customer-satisfaction metrics.[484]

279. In other contexts, the Commission has determined that while the "midpoint is relevant evidence, of course, and can serve as a useful touchstone," it is "not invariably the best measure of the return required to permit a utility to attract capital at reasonable rates, to maintain its credit rating and financial integrity, and to provide returns commensurate with those earned on other investments with equivalent risks."[485]

280. The Administrative Law Judge finds that the mean Two-Stage DCF results presented by the DOC-DER is not the sole measure of the return for GP. Rather, such DCF results, while solidly supported, must be viewed in comparison to: (1) the Department's own CAPM results of 9.38 percent; (2) the unique qualitative risks GP has compared to the proxy group companies; (3) and the competitive investment market in which it operates.

281. The record establishes that a ROE of 8.82 percent, as recommended by Mr. Addonizio, would be below all but two authorized ROEs for natural gas utilities in the country from 2009 to 2019.[486] The only two lower authorized ROEs would be 8.70 percent for the National Fuel Gas Corp in 2017, and 8.80 for Central Hudson Gas

---

[483] *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Service in Minnesota,* MPUC Docket No. E-017/GR-15-1033, Findings of Fact, Conclusions and Order (May 1, 2017).
[484] *Id. at 55.*
[485] *See, e.g., In the Matter of the Application of Interstate Power and Light Company for Authority to Increase Rates for Electric Service in Minnesota,* MPUC Docket No. E-001/GR-10-276, Findings of Fact, Conclusions, and Order at p. 10 (Aug. 12, 2011).
[486] Ex. GP-17 at 6-7 (Bulkley Summary).

and Electric Corporation in 2018.[487] All other authorized ROEs for natural gas utilities in the United States would be higher – many significantly higher -- than that suggested by Mr. Addonizio.[488] Indeed, Mr. Addonizio's recommended ROE of 8.82 percent is 90 basis points below the average authorized ROE for natural gas distribution companies in 2019.[489]

282. It is established by *Bluefield and Hope* that a rate of return should be reasonably sufficient to assure confidence in the financial soundness of the utility; maintain and support the utility's credit; enable it to attract the capital necessary for the discharge of its public duties; and be commensurate with returns on investments in other enterprises having corresponding risks.[490]

283. The record shows that it is reasonable and appropriate for the Commission to consider differences in business and investment risk between GP and the proxy group companies, and to select an authorized ROE for GP that is above the mean results for the proxy group of gas distribution companies.[491]

284. Due to the risks faced by GP and the average authorized ROEs for other natural gas companies throughout the country, it is reasonable and appropriate for the Commission to select **the mean high ROE** established in the DOC-DER DCF analysis of **9.67 percent**. This amount is closer to the DOC-DER CAPM result reached by Mr. Addonizio (9.38 percent) than Mr. Addonizio's Two-Stage DCF mean result (8.82 percent) and captures the additional risks of GP as compared to other companies in the proxy group. It allows GP to be competitive in the capital market as compared to other natural gas utilities.

C. Flotation Costs

285. GP and the DOC-DER agree that ROE estimates derived using DCF analyses must be adjusted for flotation costs. Flotation costs are the costs of issuing new shares of common stock.[492] These costs include compensation for the investment banks underwriting the issuance, legal fees, registration fees paid to the U.S. Securities and Exchange Commission (SEC), and other such costs.[493]

286. Due to the issuance costs (i.e., flotation costs), the price paid by an investor for a new share is higher than the sum received by the company issuing the new share.[494] As a result, the company must earn a higher percentage return on its

---

[487] *Id*. at Fn. 5. The next lowest would be Yankee Gas Company's ROE of 8.83 percent in 2011.
[488] Ex. GP-17 at Figure 3 (Bulkley Summary).
[489] *Id*. at 8.
[490] *Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of West Virginia,* 262 U.S. 679, 692 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).
[491] Ex. GP-16 at 71 (Bulkley Rebuttal).
[492] Ex. DER-1 at 29 (Addonizio Direct).
[493] *Id.*
[494] *Id*.

stock issuance proceeds than investors require on their investments in order to meet an investor's required rate of return.[495] A flotation cost adjustment corrects for the difference between gross and net proceeds from equity issuances.[496]

287. Even when a company is not planning on issuing a new common equity stock in the near future, a flotation cost adjustment is necessary to fairly compensate investors for the costs incurred in all past equity issuances.[497] Without accounting for flotation costs, investors will not receive their required return on their investments.[498]

288. GP provided an estimate of the flotation cost percentage on equity issued through underwriters based on two equity issuances by MDU Resources.[499] Based upon these two equity issuances, GP estimated that flotation costs for equity issuances that incurred flotation costs is 3.68 percent.[500]

289. The DOC-DER determined that GP obtained equity from processes that did not incur flotation costs and that the Company's estimate was, thus, overstated.[501] The DOC-DER, however, could not determine how much of the Company's equity did not incur flotation costs.[502] This is because the Company only provided information regarding equity issuances for the period from 2014 to 2018.[503] According to the DOC-DER, most of the Company's equity was obtained prior to 2014.[504] Consequently, it did not have data to determine how much of the equity did not incur flotation costs.[505]

290. Lacking the required data from GP, the DOC-DER estimated that half of GP's equity was obtained through means that incurred flotation costs and half was obtained through means that did not incur flotation costs.[506] Using this assumption, the DOC-DER used a flotation cost of 1.84 percent in its calculation of rate of return on equity.[507]

291. Using flotation costs of 1.84 percent, the DOC-DER calculation resulted in a flotation cost adjustment of 0.05 percent or five basis points.[508]

292. GP had an opportunity to respond to the DOC-DER's estimate contained in Mr. Addonizio's direct testimony and provide evidence of the Company's actual

---

[495] *Id*.
[496] *Id*. at 30.
[497] *Id*.
[498] *Id*.
[499] Ex. GP-14 at AEB-2, Schedule 4 (Bulkley Direct).
[500] *Id*.
[501] Ex. DER-1 at 31 (Addonizio Direct).
[502] *Id*.
[503] *Id*.
[504] *Id*.
[505] *Id*.
[506] *Id*. at 32.
[507] *Id*.
[508] *Id*.

flotation costs. In her rebuttal, Ms. Bulkley acknowledged that equity issuances via means other than public issuances are less expensive,[509] but she nonetheless failed to document MDU Resources' actual expenses relating to non-public equity issuances. Ms. Bulkley stated only that MDU Resources paid the costs of investing employee dividends,[510] but did not provide the costs associated with that employee dividend reinvestment program.

293. GP must prove the facts required to sustain its burden by a fair preponderance of the evidence.[511] The Minnesota Supreme Court has elaborated, "by merely showing that it has incurred, or may hypothetically incur, expenses, the utility does not necessarily meet its burden of demonstrating it is just and reasonable that the ratepayers bear the costs of those expenses."[512] In addition, state law requires that any doubt should be resolved in favor of ratepayers.[513]

294. In this case, GP has not demonstrated that all of its proposed flotation costs were incurred or were reasonable. While the Commission could simply disallow the flotation costs as inadequately supported, the Department has acknowledged that GP has incurred some costs in the issuance of its equity issuances. Because GP documented its public issuance expenses, but not its nonpublic issuance expenses, the DOC-DER was reasonable to recommend allowance of half of the Company's flotation costs.

295. The Administrative Law Judge, therefore, recommends that the Commission adopt a flotation cost adjustment of 0.05 percent or five basis points.

D. Elimination of Preferred Stock from Capital Structure

296. The Commission's Notice of and Order for Hearing directed the parties to address GP's preferred stock redemption.[514]

297. On April 1, 2017, GP redeemed all outstanding preferred stock.[515] Preferred stock comprised approximately 0.6 percent of the Company's average capital structure in 2017.[516]

298. GP explained that replacing preferred stock with a long-term debt issuance reduced its financing costs.[517] The Company stated that the preferred stock

---

[509] Ex. GP-16 at 67 (Bulkley Rebuttal); DER-9 at 64 (Addonizio Surrebuttal).
[510] Ex. GP-16 at 66-68 (Bulkley Rebuttal).
[511] *In re Pet. of N. States Power Co. for Auth. To Change its Schedule of Rates for Elec. Serv. In Minn.*, 416 N.W.2d 719, 722 (Minn. 1987).
[512] *Id.* at 722–23.
[513] Minn. Stat. § 216B.03 ("[E]very rate made, demanded, or received by a public utility . . . shall be just and reasonable. . . . Any doubt as to reasonableness should be resolved in favor of the consumer.").
[514] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 22, 2019).
[515] Ex. GP-12 at 5 (Nygard Direct).
[516] *Id.*

had dividend rates of 4.5 percent and 4.7 percent, while the long-term debt issuance has an interest rate of 3.36 percent.[518]

299. The DOC-DER evaluated the elimination of preferred stock from the Company's capital structure and concluded that GP's decision to redeem the preferred stock was reasonable for two reasons. First, only two companies in the DOC-DER Proxy Group included preferred stock in their capital structures, and only in small amounts.[519] Second, GP's assertion that redemption of the preferred stock reduced its financing costs was supported by the Company's preferred stock redemption net present value analysis.[520]

300. Accordingly, the DOC-DER concluded that GP's elimination of preferred stock from its capital structure was reasonable. The Administrative Law Judge concurs with the analysis of GP and the DOC-DER.

X. SALES FORECAST

A. Introduction to Forecast

301. A "test year" is the 12-month period selected by the utility for the purpose of expressing its need for a change in rates.[521] Test year sales volumes are important factors in calculating a utility's revenue requirement because sales levels affect both revenues and expenses.[522] Because sales levels are an integral input in calculating a utility's rates, the method of determining the sales levels must be reasonable.[523] Therefore, reasonable sales forecasts are an essential part of the rate-making process.[524]

302. In designing rates, test year sales volumes are used to allocate costs in the Class Cost of Service Study (CCOSS), which is then used as a benchmark comparison to establish the revenue apportionment.[525] When establishing final rates, the test year sales volumes are used to determine the overall revenue requirements, as well as the individual tariff rates.[526]

---

[517] *Id*.
[518] *Id*. at 6.
[519] Ex. DER-1 at 41 (Addonizio Direct).
[520] *Id*. at 41-42; Ex. GP-2, (Statement B, Rate Base, Schedule B-3 at 7) (Sept. 27, 2019).
[521] Minn. R. 7825.3100, subp. 17 (2019).
[522] Ex. DER-2 at 2 (Shah Direct).
[523] *Id*.
[524] *Id*.
[525] *Id*.
[526] *Id.* at 2-3.

303. The DOC-DER analyzed the Company's sales forecast and concluded that, generally, GP's regression models and sales forecasts were reasonable and recommended no adjustments to GP's proposed revenues.[527]

B. GP's Sales Forecast[528]

304. In forecasting sales for test year 2020, GP divided its customers into eight classes: residential, small firm general, large firm general, small interruptible, large interruptible, large transportation, small transportation, and grain dryers.[529]

305. Using these classes, GP forecasted sales for test year 2020 as follows:[530]

2020 projected total customers:	22,007.40 customers
2020 projected total sales:	3,813,170 Dk
2020 projected total transportation:	4,665,000 Dk

306. In assessing the Company's sales forecast, the DOC-DER reviewed whether the sales forecast was based on "normal" conditions and whether adjustments were made for known and measurable changes. The DOC-DER determined that, at a minimum, to construct a reasonable forecast, the historical sales level should be adjusted to reflect sales that would occur under "normal" weather, because weather is typically the most significant factor affecting gas usage in some rate classes.[531]

307. GP forecasted test year sales in the same manner as it did in its 2015 Rate Case: using the Ordinary Least Squares (OLS) regression analyses and averages to estimate test year sales.[532] The Company also used input changes that were improvements over the data used in its last rate case.[533]

308. The DOC-DER evaluated the source of the weather data GP used to normalize sales in this case; GP's' method for collecting and constructing the weighted weather data; and whether GP's forecasting methods were reasonable.[534] The DOC-DER concluded that GP's forecasting method was appropriate because it attempted to match sales to weather data.[535]

[527] *Id.* at 3.
[528] The OAG did not take a position on the Company's sales forecast.
[529] Ex. GP-18 at 9-19, MTS-1 at 1-2 (Shoemake Direct); Ex. GP-3 (Statement C, Workpapers, Schedule C-1, at 1-99) (Sept. 27, 2019); Ex. DER-2 at 6 (Shah Direct).
[530] Ex. GP 18, MTS-1 at 1-2 (Shoemake Direct); Ex. DER-2 at 4 (Shah Direct).
[531] Ex. DER-2 at 4 (Shah Direct).
[532] Ex. GP-18 at 5-19 (Shoemake Direct); Ex. DER-2 at 7 (Shah Direct).
[533] Ex. GP-18 at 5-19 (Shoemake Direct); Ex. DER-2 at 7 (Shah Direct).
[534] Ex. GP-18 at 5-8 (Shoemake Direct); Ex. DER-2 at 7-9 (Shah Direct).
[535] Ex. GP-18 at 5-8 (Shoemake Direct); Ex. DER-2 at 7-9 (Shah Direct).

309. The DOC-DER also assessed how GP calculated the normal weather data that it used in its forecasted test year. The Department concluded that it had no concerns regarding GP's use of the weather data.[536]

310. GP's test year sales forecast is the aggregate of several models for forecasting sales and the number of customers for its customer classes.[537] Summing the total sales for all rate classes, GP determined the total sales for the Company.[538]

311. The DOC-DER specifically assessed how "heat sensitive" test year sales were estimated by GP and how the normalized volumes were calculated for heat-sensitive customers.[539] The Department noted that the raw data was accumulated in Excel files that were then processed through analytical software referred to as "Stata."[540]

312. The DOC-DER also analyzed the model specifications and methods used to estimate the residential, small firm, large firm, and other heat-sensitive customer class models.[541] With respect to the general model specifications, the Department concluded that the transformations were reasonable.[542]

313. GP estimated 2020 test year sales for each firm rate class and each heat-sensitive interruptible and transportation customer, as well as each non-heat-sensitive interruptible and transportation customer.[543]

314. After reviewing GP's process to calculate input data and forecasting techniques and models, the DOC-DER concluded that the Company's sales forecast approach and accompanying results were reasonable and should be adopted by the Commission.[544]

315. While the Department accepted GP's sales forecast as reasonable, it did offer two recommendations for the Commission to include in its order for this case. The first recommendation was that GP provide, in all future rate cases, the information

---

[536] Ex. DER-2 at 9 (Shah Direct).
[537] *Id.* at 10.
[538] *Id.*
[539] Ex. DER-2 at 10-11, SS-2 (Shah Direct).
[540] *Id*.
[541] Ex.GP-18 at 12-14 (Shoemake Direct); Ex. DER-2 at 11-12 (Shah Direct).
[542] Ex.GP-18 at 12-14 (Shoemake Direct); Ex. DER-2 at 11-12 (Shah Direct).
[543] Ex. DER-2, at 12-13 (Shah Direct).
[544] *Id.* at 13. The DOC-DER did have one "minor concern" related to GP's retention of customer data. Specifically, in response to DOC-DER IR No. 507, the Company stated that it did "not have the data available to appropriately re-classify all Firm General Rate 70 historical billing data based on the customer's meter installed at that historical time.") *See* Ex. DER-2 at 17 (Shah Direct) (citing GP Response to IR No. 507).

required in paragraph 16 of GP's 2015 Rate Case.[545] The second recommendation was that GP be required to retain customer data for future rate cases even if there is a change in the rate structure.[546] The bases for these recommendations are explained below.

C. DOC-DER Recommendations Related to Retention of Data

316. The 2015 Rate Case Order issued by the Commission contains compliance requirements related to sales volume forecasts in GP's future rate cases.[547] The Order requires the Company to improve its forecast methodology in future rate filings by providing certain information or explaining why such information was not available.[548] Paragraph 16 of the 2015 Rate Case Order requires the Company to include the following data in all future rate cases:[549]

(a) a summary spreadsheet that links together the Company's test-year sales and revenue estimates, its CCOSS, and its rate design schedules;

(b) a spreadsheet that fully links together all raw data, to the most detailed information available and in a format that enables the full replication of GP's process that the Company uses to calculate the input data it uses in its test-year sales analysis;

(c) raw sales, customer count, billing system, and weather data that is as up to date as possible and that goes back at least 20 years;

(d) hourly historical weather (temperature) data, rather than (or in addition to) daily historical data;

(e) if, in the future, GP updates, modifies, or changes its billing system, a bridging schedule that fully links together the old and new billing systems and validates that there is no difference between the two billing systems;

(f) any, and all, data used for its sales forecast 30 days in advance of its next general rate case; and,

(g) detailed information sufficient to allow for replication of any and all Company derived forecast variables.

---

[545] Ex. DER-2 at 23 (Shah Direct). *See In the Matter of the Petition by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket 15-879, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 51-52 (Sept. 6, 2016).
[546] Ex. DER-2 at 23 (Shah Direct).
[547] *In the Matter of the Petition by Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for Authority to Increase Natural Gas Rates in Minnesota*, MPUC Docket 15-879, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER at 51-52 (Sept. 6, 2016).
[548] *Id.*
[549] *Id.*

317. The DOC-DER confirmed that the Company addressed all of the above requirements in this current proceeding.[550] However, the DOC-DER expressed a "minor" concern about the information supplied in response to the requirement of Paragraph 16(c) of the Order.[551]

318. Paragraph 16(c) requires GP to provide "raw sales, customer count, billing system, and weather data that is as up to date as possible and *that goes back at least 20 years*" or explain why such data is not available.[552]

319. The Company's sales forecast in this case did not use information going back at least 20 years. GP explained that the Company made changes to customer rate classes in 2004 and 2007.[553] Those changes resulted in, among other things, pre-2007 billing data that was not consistent with the current rate structure.[554] As a result, GP did not use that data in the instant sales forecast.[555] According to GP, if the Company had used data collected prior to 2004, it would have had to make assumptions about the historical billings and re-classify the data as either residential or firm general service.[556]

320. In addition, from 2004 through mid-2007, firm general service customers were all billed under the same rate classification.[557] Therefore, additional assumptions would have to be made to re-classify the data from 2004 through mid-2007 as either small or large firm general service.[558] To avoid making incorrect assumptions on any historical billing data that did not match the Company's current rate structure, GP did not utilize customer use data prior to 2007 in its sales forecast.[559] Consequently, the Company included only 15 years of residential billing data and only 11 years of firm general service billing data in its weather normalization process.[560]

321. To evaluate the effect of GP's exclusion of data, the DOC-DER requested IRs for data from 2004 through 2007 for the firm general classes.[561] Despite the DOC-DER's requests, GP did not provide the data.[562] Instead, the Company provided detailed reasons for its inability to provide data for the years prior to 2008.[563]

322. After considering GP's explanation for the limitation in data, the DOC-DER concluded that the Company complied with the 2015 Rate Case Order because it

---

[550] Ex. DER-2 at 5-6 (Shah Direct); Ex. GP-18 at 2-5 (Shoemake Direct).
[551] Ex. DER-2 at 13-18 (Shah Direct)
[552] *Id.* at 13-14 (citing GP 2015 RATE CASE ORDER, Ordering Para. 16) (emphasis added).
[553] Ex. DER-2 at 14 (Shah Direct).
[554] Ex. GP-18 at 8-11 (Shoemake Direct).
[555] *Id*.
[556] *Id*.
[557] *Id*.
[558] *Id*.
[559] *Id*.
[560] Ex. GP-18 at 8-11 (Shoemake Direct); Ex. DER-2 at 14-16 (Shah Direct).
[561] Ex. DER-2 at 16-17, SS-3 (Shah Direct) (GP Responses to Department IRs Nos. 501-512).
[562] *Id*. at 16.
[563] *Id*. at 16-17, SS-3 (Shah Direct) (GP Responses to Department IRs Nos. 501-512).

adequately explained why the information was not available.[564] Thus, even though GP did not provide the requested data, it was able to explain why such data was not available, as allowed in the 2015 Rate Case Order.[565]

323. The DOC-DER recommends that the Commission continue to require GP to comply with Paragraph 16 from the 2015 Rate Case Order in all future rate cases.[566] GP has agreed to this recommendation.[567]

324. Because of the lack of data available before 2004 and between 2004 and 2007, the DOC-DER also recommends that the Commission require GP to retain customer data such that, in the event the Company proposes different rate structures in the future, past data would remain available to compare the different rate structures in subsequent rate cases.[568] GP agrees to this recommendation.[569]

325. Based upon the review of the DOC-DER, the Administrative Law Judge recommends that the GP's sales forecast for test year 2020 be accepted as reasonable. The Judge further recommends that the Commission adopt the DOC-DER's recommendations regarding the retention of data and the continuation of the compliance requirements set forth in Paragraph 16 of the 2015 Rate Case Order.

XI. CLASS COST OF SERVICE STUDY (CCOSS)[570]

A. CCOSS Objective and Characteristics

326. A Class Cost of Service Study (CCOSS) is used to identify the responsibility of each customer class for costs incurred by the utility in providing service. The CCOSS can be used to help determine how costs should be recovered from customer classes through rate design.[571] A CCOSS addresses "cost causality," an assessment of which costs are attributable to which customer classes so that the expenses of the utility can be fairly and appropriately allocated among the various customer classes in rate design.[572]

327. There are three steps in performing a CCOSS. First, costs are "functionalized" or grouped according to their purpose. Second, costs are classified into three basic categories: (1) customer costs; (2) energy or commodity costs; and

---

[564] *Id*. at 17.
[565] *Id*.
[566] *Id*. at 18.
[567] Ex. GP-19 at 2 (Shoemake Rebuttal); Ex. DER-10 at 2 (Shah Surrebuttal).
[568] Ex. DER-2 at 18 (Shah Direct).
[569] Ex. DER-17 (Shah Summary). The parties agreed that, whether it is reasonable for GP to make assumptions about forecasting data in future cases when there is a change in rate structure, is a question to be decided in future cases and not in this docket. Ex. DER-10 at 4-8 (Shah Surrebuttal); Ex. DER-17 (Shah Summary).
[570] The OAG did not take a position on Class Cost of Service in this proceeding.
[571] Ex. DER-3 at 3 (Ouanes Direct).
[572] *Id.*

(3) demand or capacity costs. Third, costs are allocated to the various customer classes.[573]

328. Costs are typically functionalized by the Uniform System of Accounts, as provided by the Federal Energy Regulatory Commission (FERC).[574] These accounts group costs into their various functions, such as: production (costs associated with producing, purchasing, or manufacturing gas); storage (costs associated with storing gas normally during off-peak for use in times of cold weather); transportation (costs incurred in transporting gas from interstate pipelines to the distribution system); distribution (costs incurred to deliver the gas to the customers, such as gas distribution mains and meters); and other costs (costs that do not fit the above functions, including general and administrative costs).[575]

329. The functionalized costs are then classified as "customer," "demand," or "energy costs," according to how they are incurred.[576]

330. "Customer costs" are the operating and capital costs which vary with the number of customers served rather than with the amount of utility service supplied. These costs are associated with "the theoretical distribution system that would be needed to serve customers at nominal or minimal load conditions."[577]

331. "Demand or capacity costs" are the expenses incurred to serve the peak demand on the system and do not directly vary with the number of customers or their annual usage. They include the costs associated with distribution mains in excess of the minimum size the theoretical distribution system that would be needed to serve customers at nominal or minimal load conditions."[578]

332. "Energy or commodity costs" consist of those costs that vary with the quantity of gas consumed by each class.[579]

333. The functionalized and classified costs are then allocated among the various customer classes.[580]

---

[573] *Id.* at 3-4, SO-3 at 1 (Ouanes Direct) (citing *Gas Distribution Rate Design Manual of the National Association of Regulatory Utility Commissioners* at 20, June 1989 (*Gas Manual*)).
[574] 18 C.F.R. 201 (2019) (Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act).
[575] Ex. DER-3 at 3, SO-3 at 1-3 (Ouanes Direct) (*Gas Manual* at 20-22).
[576] Functionalized costs that may not be readily categorized as customer, energy, or demand are generally classified and allocated on a composite basis of other cost categories. For example, administrative and general expenses may be classified and allocated on the same basis as the sum of the other operating and maintenance expenses, excluding the cost of gas. Ex. DER-3 at 4-5, SO-3 at 7 (Ouanes Direct) (*Gas Manual* at 26).
[577] Ex. DER-3, SO-4 (Ouanes Direct) (*Gas Rate Fundamentals of the American Gas Association* at 136 (4th ed. 1987)).
[578] *Id*., SO-3 at 4-5 (*Gas Manual* at 23-24).
[579] *Id.,* SO-3 at 4 (*Gas Manual* at 23).

334. "Customer costs" are allocated among the customer classes based on the number of customers in each class, typically weighted to reflect, for example, differences in metering costs among customer classes.[581] "Demand or capacity costs" are allocated among the customer classes based on the demand imposed on the system by each class during specific peak hours.[582] "Energy or commodity costs" are allocated among the customer classes based on the energy the system must supply to serve the various customer classes.[583]

335. The CCOSS is a mathematical model consisting of two types of variables, endogenous and exogenous variables, as well as the relationships between those variables.[584] Endogenous variables are the variables that are determined within the model.[585] For example, the revenue requirement for the residential class is an endogenous variable determined within the model.[586] Its value becomes known only after running the CCOSS.[587] Exogenous variables are the variables whose values are determined outside of the model.[588] For example, test year costs by FERC account, sales data, or the rate of return, are exogenous variables because they are set outside of the CCOSS.[589] The values of the endogenous variables are, by construction, dependent on the values of the exogenous variables and the specific relationships between variables included in the model.[590]

336. Because both endogenous and exogenous variables go into the CCOSS, the revenue requirement for each customer class will depend not only on the Commission's decision on the specific classifications and allocation methods within the CCOSS, but also on the Commission's decisions on specific outside variables, such as the amounts and items in the rate base, expenses, the rate of return, and sales forecast.[591] The Commission's decisions on these variables will be reflected in final rates.[592]

---

[580] Ex. DER-3 at 6, SO-3 at 7 (Ouanes Direct) (*Gas Manual* at 26). The functionalized and classified costs that may not be readily categorized as customer, energy, or demand are generally allocated on a composite basis of other cost categories. For example, administrative and general expenses may be allocated on the basis of the sum of the other operating and maintenance expenses, excluding the cost of gas.
[581] *Id*. at 6.
[582] *Id*.
[583] *Id*.
[584] *Id*. at 7.
[585] *Id*.
[586] *Id*.
[587] *Id*.
[588] *Id*.
[589] *Id*.
[590] *Id*.
[591] *Id*. at 7-8.
[592] *Id*. at 8 (referencing testimony of Michael Zajicek, Department witness on the topic of "rate design").

B. GP's Class Cost of Service Study

337. As required by the Commission's 2015 Rate Case Order,[593] the Company filed three embedded class cost of service studies: two "minimum system method" studies and a "basic customer method" study. GP used the basic customer method as the Company's starting point for its proposed rate design.[594]

338. The minimum system method CCOSS and the basic customer method CCOSS differ in the way they classify distribution mains, which are included in FERC Account No. 376. The basic customer method CCOSS classifies distribution mains as 100 percent demand-related costs.[595] In contrast, the two minimum system method studies used by the Company (the MS1 CCOSS and the MS2 CCOSS)[596] classified distribution mains based on demand-related and customer-related costs on a minimum-size analysis.[597]

339. Although the studies were based on reasonably current data,[598] GP's proposal misclassified or misallocated costs associated with the following FERC accounts:[599]

- FERC Account No. 374, Land and Land Rights.
- FERC Account No. 375, Structures and Improvements.
- FERC Account No. 886, Maintenance of Structures and Improvements.
- FERC Account No. 387, Other Equipment.
- FERC Account No. 385, Industrial Measuring and Regulating Station Equipment.

---

[593] *Id*. at 9-10 (*citing* GREAT PLAINS 2015 RATE CASE ORDER at 36. (In the GREAT PLAINS 2015 RATE CASE ORDER, the Commission found no reliable CCOSS in the record, and decided to retain the Company's then-current class allocation, as recommended by the Department and the OAG. The Commission reasoned that it "previously found Great Plains' existing class revenue apportionment to be reasonable, and nothing in the current docket leads the Commission to reach a contrary conclusion. Consequently, the Commission will retain the Company's current class allocation, as recommended by the Department and the OAG.")).
[594] Ex. GP-25 at 11 (Hatzenbuhler Direct); Ex. DER-3 at 8 (Ouanes Direct).
[595] Ex. GP-2 (Vol. III, Statement E, Rate Structure and Design, Schedule E-2b) (Sept. 27, 2019) publ. at: Great Plains Proposed CCOSS; *see also* Ex. GP- 25 at 11 (Hatzenbuhler Direct).
[596] Ex. GP-3 (Statement E, Rate Structure and Design Workpapers, Schedule E-2 at 20-54, 63-97 of 105) (Sept. 27, 2019) (Great Plains Alternative E-2), publ. at: Great Plains Alternative CCOSSs; *see also* Ex. GP-25 at 9-11 (Hatzenbuhler Direct).
[597] Ex. DER-3 at 9 (Ouanes Direct).
[598] *Id*. at 10, SO-5.
[599] *Id.* at 10-11.

- FERC Account No. 890, Maintenance of Measuring and Regulating Station Equipment-Industrial.

- FERC Account No. 876, Measuring and Regulating Station Expenses-Industrial.

- FERC Account No. 892, Maintenance of Services.

340. The DOC-DER detailed why it believed each of these eight FERC accounts had been misclassified or misallocated in the Company's initial filing.[600] The DOC-DER recommended that the Company reclassify and reallocate these accounts, as follows, to better reflect cost causation:[601]

- classify and allocate Land and Land Rights (FERC Account No. 374) on the same basis as Distribution Plant;

- classify and allocate Structures and Improvements (FERC Account No. 375) on the same basis as Distribution Plant;

- classify and allocate Maintenance of Structures and Improvements (FERC 1 Account No. 886) on the same basis as Distribution Plant;

- classify and allocate Other Equipment (FERC Account No. 387) on the same basis as Distribution Plant;

- identify the customer classes that use special and expensive installations of measuring and regulating station equipment located on the distribution system and allocate the costs of Industrial Measuring and Regulating Station Equipment (FERC Account No. 385) and Maintenance of Measuring and Regulating Station Equipment-Industrial (FERC Account No. 890) to only those classes;

- identify the customer classes that use large measuring and regulating stations located on local distribution systems and allocate the costs of Measuring and Regulating Station Expenses-Industrial (FERC Account No. 876) to only those classes;

[600] *Id.* at 13-17.
[601] Ex. DER-11 at 1-2 (Ouanes Surrebuttal).

- allocate Maintenance of Services (FERC Account No. 892) on the same basis as Services (FERC Account No. 380); and,

- use for each type and size of pipe a more reliable current unit replacement cost ($ per foot) of the installed distribution pipes than the ones provided under GP's third proposed minimum-size method (MS3) and provide in rebuttal testimony a revised minimum size CCOSS using the outcome of such a revised minimum-size method with the adjustments to the classification and/or allocation of the FERC accounts described above.

341. In response to the DOC-DER's requests and recommendations, GP explained that these accounts represented relatively small dollar amounts when compared to the overall plant-in-service costs and distribution expenses.[602] The Company then asserted that correcting the misclassifications and misallocations would have no material effect on the results of the CCOSS in the instant case.[603]

342. While not reclassifying or reallocating these accounts in the current case, GP did agree to reclassify and/or reallocate the eight FERC accounts for future rate cases.[604]

343. In the end, GP and the DOC-DER agreed that, because a reclassification and/or reallocation of the eight identified FERC accounts would have no material effect on the overall results of the CCOSS in this case, the DOC-DER did not require the Company to make the changes to the classifications and allocations in this case.[605] The Company, in turn, agreed to incorporate the changes in classification or allocation to these eight FERC accounts in its next rate case.[606]

C. Classification Methods for Distribution Mains (FERC Account 376)

1. Background

344. With respect to FERC Account No. 376, GP proposed to classify all of its distribution mains as solely demand costs, which assumed that demand was the only factor that drives the utility's investment in distribution mains.[607]

[602] Ex. GP-26 at 18 (Hatzenbuhler Rebuttal).
[603] *Id*.
[604] *Id*. at 17-18.
[605] Ex. DER-11 at 3 (Ouanes Surrebuttal).
[606] Ex. GP-26 at 17-18 (Hatzenbuhler Rebuttal).
[607] Ex. DER-3 at 18 (Ouanes Direct).

345. The DOC-DER disagreed with this classification because the number of customers -- not just demand for gas -- drives investment in distribution mains.[608] The DOC-DER concluded that GP's distribution mains should be classified as both demand costs and customer costs.[609] This is because the distribution system exists to serve its two functions: (1) delivering gas to customers' residences or businesses (customer costs); and (2) ensuring that the distribution system is large enough to provide reliable service (demand costs).[610]

346. Notably, in its 2015 Rate Case, GP classified distribution mains as both demand and customer costs.[611] However, in the instant case, GP proposed to classify distribution mains as entirely demand costs due to "data limitations." As its rationale, GP stated:

> Due to the data limitations previously discussed and the resulting inability to perform a minimum system study to the specifications set forth by the Commission, the Company opted to rely on the Basic Customer Method in its embedded class cost of service study. This was accomplished by utilizing a demand factor for the allocation of the distribution mains plant balance and utilizing a customer factor for only the services, meters, service regulators, and customer billing software rate base items.[612]

347. The "data limitations" identified by GP is that it has "very limited detail" available for pipes installed prior to when GP purchased the Company in 2000.[613] According to GP, the "data limitations" precluded GP from providing and supporting a reliable, current unit replacement cost (per foot) of the installed distribution pipes.[614]

2. Data Issues

348. Minnesota gas utilities generally use historical records for their distribution system, including the amount of pipe laid, the diameter of the pipe, the type of pipe (plastic or steel), and the book cost per foot of pipe for each type.[615] The utility then inflates the costs of these projects using the Handy-Whitman (HW) Index of Public Utility Construction Costs to normalize the cost data in terms of current replacement costs.[616] Because the construction period of a gas utility's current distribution system generally covers several decades, equipment should be priced out at current replacement values to determine current unit replacement costs, not at original

[608] *Id*.
[609] *Id*.
[610] *Id*. at 19.
[611] *Id.* at 22-23.
[612] Ex. GP-25 at 11 (Hatzenbuhler Direct).
[613] *Id*. at 9-10.
[614] *Id*. at 10. Note that the pipe installed post-2000 represent approximately 30 percent of the total footage for the system and 65 percent of the plant balance as of December 31, 2018. *Id.*
[615] Ex. DER-3 at 28 (Ouanes Direct).
[616] *Id*.

investment cost.[617] This process provides for comparable current replacement investment values for each size and type of equipment.[618]

349. The DOC-DER identified several concerns with GP's implementation of its minimum-size studies, including: the lack of disaggregated data to provide for a meaningful minimum-size study; the grouping together of all pipes sized less than two inches; and the Company's failure to include supporting data for pipes installed prior to 2000.[619] In addition, in one or both minimum-size studies, the customer component was calculated based on a limited portion of footage of mains (instead of all installed distribution mains) and/or book cost data (instead of current unit replacement costs).[620]

350. As a result, the DOC-DER recommended against approval of the two minimum-size methods, as initially proposed filed by GP (MS1 and MS2).[621] The DOC-DER also recommended that GP provide, in its rebuttal testimony, an improved minimum-size method (the MS3) using the current unit replacement cost (per foot) of the installed distribution pipes for each pipe type and size.[622] Finally, the DOC-DER recommended that GP provide a revised medium-size CCOSS using the outcome of the revised minimum-size method, with the adjustments to the classification and/or allocation of the FERC accounts that the DOC-DER recommended.[623]

351. GP did not complete a revised minimum-size method CCOSS in response to the DOC-DER's recommendation. Instead, GP witness Jordan Hatzenbuhler testified that:

> the class cost of service study serves as a guide in the revenue allocation and rate design process and is generally not adhered to absolutely. As has been discussed, the Basic Customer Method class study that was utilized is useful if the analyst recognizes the effects of classifying distribution mains as entirely demand related. Because the Company is not proposing to bring the classes to anywhere near even the knowingly conservative results of the Basic Customer Method class study, I don't feel introducing an additional class study would be beneficial. This is especially true considering Great Plains, the Department and the OAG all agree the Company's proposed revenue allocation is reasonable and should be adopted.[624] I appreciate Dr. Ouanes working with Great Plains to further understand the data limitations the Company faces when preparing minimum system

---

[617] *Id*.
[618] *Id*.
[619] *Id*. at 30-32.
[620] *Id*. at 30-32.
[621] *Id*. at 32-33.
[622] *Id*.
[623] *Id*. at 33.
[624] Contrary to Mr. Hatzenbuhler's statement, the OAG did not take a position on GP's proposed revenue allocation. *See* Ex. OAG-2 at 2 (Lebens Surrebuttal).

> studies and will take [sic] apply his suggestions when preparing the Company's next class study.[625]

352. Because of the Company's alleged "data limitations" (which the Company asserted precluded it from providing and supporting current unit replacement costs of the installed distribution pipes), the DOC-DER concluded that there was no reasonably supported minimum-size study available in the record.[626] Moreover, because all basic customer method studies (including the one GP provided) classify distribution mains as entirely demand-related, use of the results could not be made without recognizing the "bias inherent in those results."[627] The "bias inherent" in the results, according to the DOC-DER, is that classifying distribution mains as entirely demand-related results in costs being under-classified as costumer related and over-classified as demand related.[628]

353. Consequently, the Department concluded that the Commission should not approve the basic customer method CCOSS,[629] nor the three minimum-size methods and corresponding CCOSSs,[630] in the record. The Administrative Law Judge concurs with the DOC-DER.

D. Summary of Recommendations Related to CCOSS

354. Based upon the agreements between GP and the DOC-DER, the Administrative Law Judge recommends that the Commission not approve the CCOSSs that GP presented in this case.

355. In addition, the Commission should require the Company, in its next rate case, to reclassify and/or reallocate the following eight FERC accounts, as recommended by the DOC-DER in this case: 374, 375, 886, 387, 385, 890, 876, and 892.

356. Finally, the Commission should perform an improved minimum-size CCOSS using per-foot replacement costs for each type and size of installed distribution pipes, and file such a study in the next general rate case, as recommended by the DOC-DER.

---

[625] Ex. GP-26 at 18-19 (Hatzenbuhler Rebuttal); Ex. DER-11 at 4 (Ouanes Surrebuttal).
[626] Ex. DER-11 at 5 (Ouanes Surrebuttal).
[627] *Id*. at 5-6.
[628] *Id.* Specifically, the demand allocator used (allocator number 2) assigns a lower portion of costs to the residential class and a higher portion of costs to the other classes when compared to the customer allocator used (allocator number 4).
[629] Ex. DER-3 at 17-26 (Ouanes Direct); Ex. DER-11 at 6 (Ouanes Surrebuttal).
[630] Ex. DER-3 at 30-32 (Ouanes Direct); Ex. DER-11 at 6 (Ouanes Surrebuttal).

XII. RATE DESIGN AND APPORTIONMENT OF REVENUE RESPONSIBILITY

A. Customer Service Extension Tariff

357. Since 1995, the Commission has requested that the DOC-DER investigate every gas utility company's service additions to rate case due to new service extensions during a general rate case to ensure that: (1) the local distribution companies (LDC) are applying their tariffs correctly and consistently; (2) the service additions are "appropriately cost and load justified;" and (2) wasteful additions to plant and facilities are excluded from the rate base.[631]

358. In its Order Terminating Investigation and Closing Docket in Docket No. G-999/CI-90-563, dated March 31, 1995 (1995 Order), the Commission directed the DOC-DER to evaluate GP's customer service extension tariff in all general rate proceedings.[632] The Order requires the DOC-DER to consider six questions as part of this analysis.[633] Those six questions include:[634]

- Should the "free" footage or service extension allowance include the majority of all new extensions with only the extremely long extensions requiring a customer contribution-in-aid-of-construction (CIAC)?

- How should the company determine the economic feasibility of service extension projects and are the excessive footage charges collected?

- Should the company's service extension policy be tariffed in number of feet without consideration to varying construction costs among projects or should the allowance be tariffed as a total dollar amount per customer?

- Is the company's extension charge refund policy appropriate?

- Should customers be allowed to run their own service line from the street to the house (or use an independent contractor) if it would be less expensive than having the utility construct the line?

- Should the company be required to offer its customers financing for service extension charges?

---

[631] Ex. DER-4 at 3 (Zajicek Direct).
[632] *Id*. at 7-8.
[633] *Id*.; Ex. GP-31 at 16-24 (Bosch Direct).
[634] Ex. DER-4 at 7-8 (Zajicek Direct).

359. GP answered each of these questions in its submissions and the DOC-DER analyzed those answers.[635]

360. With respect to the first question, the DOC-DER concluded that GP's extension procedures struck an appropriate balance by allowing most new customers to obtain extensions needed for service at reasonable rates, while not requiring existing customers to pay for unusually long service extensions.[636]

361. With respect to the second question, the DOC-DER concluded that GP's application of its Maximum Allowable Investment (MAI) policy to extension projects exceeding the free footage limit was reasonable.[637]

362. With respect to the third question, the DOC-DER concluded that the Company's preference for a free footage allowance, as opposed to a per-customer dollar allowance, was reasonable even if other approaches might be more accurate.[638] This was because the free footage allowance is: (1) based on typical construction circumstances; (2) easier for customers to understand; and (3) administratively efficient to administer.[639]

363. With respect to the fourth question, the DOC-DER concluded that GP's extension charge refund policy was reasonable because it makes contributions for firm gas main extensions refundable for a period of up to five years as additional customers are connected to the main for which the advance was made.[640]

364. With respect to the fifth question, the DOC-DER concluded that GP's policy of not allowing customers to install their own service lines (either independently or with the use of private contractors) was reasonable because the Company is responsible for the safe operation and maintenance of its service lines.[641]

365. With respect to the sixth question, the DOC-DER considered GP's policy of not providing financing to customers responsible for a service extension cost contribution. The Company does not offer financing because of the additional risk associated with providing it.[642] The Department concluded that such a policy was reasonable and that private financing (such as from a bank) would still be available to customers.[643]

---

[635] *Id*. at 8-21; Ex. GP-31 at 16-20 (Bosch Direct).
[636] Ex. DER-4 at 10-12 (Zajicek Direct).
[637] *Id*. at 12.
[638] *Id*. at 13-14.
[639] *Id*.
[640] *Id*. at 14-15.
[641] *Id*. at 15-16.
[642] Ex. GP-31 at 19-20 (Bosch Direct).
[643] Ex. DER-4 at 17 (Zajicek Direct).

366. The Commission's 1995 Order also directs the DOC-DER to address three additional "concerns" related to GP's application of its service extension tariff.[644] Those three concerns include: (1) whether GP correctly and consistently applied its extension tariff since its last rate case; (2) whether GP's service-related additions are appropriately cost and load justified; and (3) whether GP's extension practices prevent wasteful additions to plant and facilities.[645]

367. In evaluating these three concerns, the Department concluded that: (1) GP correctly applied its customer service extensions between 2015 and 2018;[646] (2) GP's main and service line extensions are appropriately cost and load justified;[647] and (3) GP's policies ensure that wasteful plant additions are not included in the Company's rate base.[648]

368. GP proposes two changes to its extension policies. First, the Company proposed to update the Levelized Annual Revenue Requirement (LARR) factor to reflect changes to cost levels and capital structure that occur as a result of this proceeding.[649] Second, GP proposes to update its Maximum Allowable Investment (MAI) calculation to reflect revenue associated with its GUIC Rider adjustment and Margin Sharing Credit.[650]

369. The DOC-DER concluded that both proposals are reasonable so long as the LARR factor and MAI calculation are updated to reflect the Commission's final decision relating to the Margin Sharing Credit and GUIC Rider revenues.[651]

B. Rate Design Principals

370. Due to the monopoly-like nature of the retail market for natural gas and the absence of competition in Minnesota, government regulation approximates the results that could be achieved in a competitive environment when designing rates.[652] To do this, certain basic principles are applied.[653]

371. First, rates should be designed to allow a utility company a reasonable opportunity to recover its revenue requirements, including the cost of capital.[654]

372. Second, rates should promote the efficient use of resources.[655] As part of this principle, rates should be related to the cost of serving each customer class,

---

[644] *Id*. at 17-20.
[645] *Id*.
[646] *Id*. at 17-18.
[647] *Id*. at 19.
[648] *Id*. at 19-20.
[649] Ex. GP-31 at 24 (Bosch Direct).
[650] *Id*.
[651] Ex. DER-4 at 20-21 (Zajicek Direct).
[652] *Id*. at 22.
[653] *Id*. at 21-22.
[654] *Id*.

thereby sending a price signal to the customer to promote conservation and efficiency.[656]

373. Third, increase in rate charges should be gradual and have appropriate continuity with past rates.[657] Rate stability and continuity protect customers from "rate shock" associated with sudden increases in costs and afford utilities a steady flow of revenue to meet their operating requirements.[658] Rate shock is particularly difficult for residential consumers, many of whom may have difficulty in adjusting to sudden price changes.[659]

374. Finally, rates should be understandable and easy to administer.[660] Maintaining clear and concise rates helps ensure that customers have a better understanding about the amounts and different types of charges on their bills so that they can make informed decisions about how they use gas.[661]

375. Minnesota law imposes certain requirements and guidance for rate making. First, rates must be reasonable and not unreasonably discriminatory.[662] According to Minn. Stat. § 216B.07 (2018), "No public utility shall, as to rates or service, make or grant any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or advantage." Similarly, Minn. Stat. § 216B.03 provides that "[r]ates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but shall be sufficient, equitable, and consistent in application to a class of consumers."

376. At the same time, the Commission must consider the ability to pay as a factor in setting rates,[663] and "[a]ny doubt as to reasonableness should be resolved to favor the consumer."[664] Thus, while rates cannot be discriminatory or give unreasonable preference to certain classes, they must also reflect a consideration of that customer class's ability to pay. This is particularly true for the residential class.[665]

377. Minnesota law also requires the Commission to set rates to promote energy conservation and the use of renewable energy.[666]

---

[655] *Id*.
[656] *Id*. at 22.
[657] *Id*. at 21-22.
[658] *Id*. at 22.
[659] *Id*.
[660] *Id*. at 21.
[661] *Id*. at 22.
[662] *See* Minn. Stat. §§ 216B.07,.03.
[663] Minn. Stat. § 216B.16, subd. 15 (2018).
[664] Minn. Stat. § 216B.03.
[665] Ex. DER-4 at 22 (Zajicek Direct).
[666] *See* Minn. Stat. §§ 216B.03, 216C.05, subd. 1 (2018).

C. GP Customer Classes

378. GP is a natural gas distribution utility with several types and combinations of service types: sales and transportation, firm and interruptible, market-rate and standard service.[667]

379. Residential and small business customers must choose sales service.[668] Large customers on GP's system, however, can choose between sales service or transportation service.[669]

380. Customers who sign up for sales service rely on GP to procure and deliver their gas.[670] GP does this by arranging for gas to be delivered to Town Border Stations (TBS) and then delivers the gas through its own distribution system to individual customers.[671]

381. Customers who sign up for transportation-only service procure their own natural gas supply through other, unregulated gas suppliers.[672] These third-party gas suppliers then deliver the gas to a TBS and GP transports that gas through GP's distribution system to the customer.[673]

382. Customers on sales and transportation services may choose between firm service or interruptible service.[674] Firm service is not subject to curtailment or interruption by the Company unless there is an emergency and is priced to include the costs of providing this consistency and reliability.[675] Customers with interruptible service, on the other hand, can have their service curtailed or interrupted by GP as needed to maintain system reliability for all customers.[676] For this reason, interruptible service is less expensive than firm service.[677]

383. Customers who are deemed to be subject to "effective competition" under Minn. Stat. § 216B.163 (2018)[678] may take service under a flexible tariff (at market rate), while all other customers must take service under a standard tariff.[679]

---

[667] Ex. DER-4 at 25 (Zajicek Direct).
[668] *Id*.
[669] *Id*.
[670] *Id*.
[671] *Id*.
[672] *Id*.
[673] *Id*. at 25-26.
[674] *Id*. at 26.
[675] *Id*.
[676] *Id*.
[677] *Id*.
[678] Pursuant to Minn. Stat. § 216B.163, subd. 1(b), "'Effective competition' means that a customer of a gas utility who either receives interruptible service or whose daily requirement exceeds 50,000 cubic feet maintains or plans on acquiring the capacity to switch to the same, equivalent, or substitute energy supplies or service, except indigenous biomass energy supplies composed of wood products, grain, biowaste, and cellulosic materials at comparable prices from a supplier not related by the Commission."

384. Currently, GP has two firm service classes (Residential and General Firm Service) and three interruptible service classes (Interruptible Grain Drying; Small Interruptible; and Large Interruptible).[680]

385. The Small Interruptible and Large Interruptible classes are further divided into sales and transportation classes (Small Interruptible Sales, Small Interruptible Transportation, Large Interruptible Sales, Large Interruptible Transportation).[681]

386. Below is a summary of GP's customers by class:[682]

Class	Number of Customers	Annual Usage (Dk)
Residential	18,808	1,527,457
Small Firm	2,014	286,401
Large Firm	1,064	1,055,652
Interruptible Grain Drying	30	191,639
Small Interruptible Sales	95	392,421
Small Interruptible Transport	6	85,118
Large Interruptible Sales	7	359,600
Large Interruptible Transport	11	885,658

387. There are generally three types of costs considered when creating utility rates: customer costs, demand costs, and commodity costs.[683] Customer costs are generally the non-gas costs required to connect customers and provide service.[684] These costs include "the theoretical distribution system that would need to serve customers at nominal or minimal load conditions."[685]

388. Demand or capacity costs are those costs incurred to serve the peak demand on the system.[686] They include "the costs associated with distribution mains in excess of minimum size."[687]

389. Commodity costs are those costs that vary with the quantity of gas consumed.[688]

---

679 Ex. DER-4 at 26-27 (Zajicek Direct).
680 *Id*. at 27.
681 *Id*.
682 Ex. GP-2 (Statement E, Rate Structure and Design, Schedule E-2c) (Sept. 27, 2019).
683 Ex. DER-4 at 30 (Zajicek Direct).
684 *Id*.
685 Ex. DER-3, at SO-4 (Ouanes Direct).
686 *Id*. at 5.
687 *Id*. at SO-3 at 4-5.
688 *Id*. at 5.

390. Customer charges apply to each customer for each month the customer is on GP's system.[689] Commodity charges apply to each unit (therm or Dk) of gas that a customer actually uses.[690] Demand charges stem from capacity costs and are assessed based upon the customer's highest demand in a specific time period and are billed on a dollar-per-unit (therm or DK) basis.[691]

D. Revenue Apportionment

391. Based on its Class Cost of Service Study (CCOSS), GP proposes to change how its revenue requirement is apportioned among its six customer classes. The following tables summarize GP's current and proposed apportionment of revenue responsibility:[692]

GP's Current and Proposed Apportionment of Revenue Responsibility ($)

Class	Current Apportionment w/gas (a)	Proposed Apportionment w/gas (b)	GP's Cost-Based (CCOSS) Apportionment w/gas (c)	Proposed Increase (d)	Current Revenue deficiency (a) – (c)	Gas Utility Infrastructure Cost (GUIC) (f)	Effective Increase: Proposed Increase (d) – (f)
Residential	$10,145,514	$12,120,411	$13,743,664	$1,974,897	($3,598,150)	$380,948	$1,593,949
Firm General	$7,896,682	$9,126,415	$8,680,503	$1,229,733	($783,821)	$240,496	$989,237
Interruptible Grain Drying	$812,834	$939,405	$764,380	$126,571	$48,454	$27,181	$99,390
Small Interruptible Gas Sales	$1,790,007	$1,894,918	$1,484,213	$104,911	$305,794	$59,609	$45,302
Small Interruptible Gas Transport	$114,039	$139,191	$45,219	$25,152	$68,820	$6,733	$18,419
Large Interruptible Gas Sales	$1,307,839	$1,353,246	$1,282,622	$45,407	$25,217	$39,664	$5,743
Large Interruptible Gas Transport[7]	$1,801,840	$1,935,087	$1,507,992	$133,247	$293,848	$24,448	$108,799
Total	$23,868,755	$27,508,674	$27,508,593	$3,639,918	($3,639,838)	779,079	$2,860,839

[689] Ex. DER-4 at 31 (Zajicek Direct).
[690] *Id.*
[691] *Id.*
[692] Ex. DER-4 at 41-42, Tables 3 and 4 (Zajicek Direct) (summarizing Ex. GP-2 (Statement E, Rate Structure and Design, Schedule E-1 at 1-4) (Sept. 27, 2019)).

GP's Current and Proposed Apportionment of Revenue Responsibility
Proposed Changes in Relative Responsibilities (%)

Class	Current Apportionment	GP's Proposed Apportionment	Cost Based Apportionment	Percent Increase w/out gas	Percent Increase w/out gas and w/out GUIC	Percent Increase w/ Cost of Gas	Percent Increase w/ Cost of Gas and W/out GUIC
Residential	42.51%	44.06%	49.96%	46.36%	37.42%	19.47%	15.71%
Firm General	33.08%	33.18%	31.56%	45.12%	36.30%	15.57%	12.53%
Interruptible Grain Drying	3.41%	3.41%	2.78%	52.39%	41.14%	15.57%	12.23%
Small Interruptible Gas Sales	7.50%	6.89%	5.40%	16.91%	7.30%	5.86%	2.53%
Small Interruptible Gas Transport	0.48%	0.51%	0.16%	22.06%	16.15%	22.06%	16.15%
Large Interruptible Gas Sales	5.48%	4.92%	4.66%	19.24%	2.43%	3.47%	0.44%
Large Interruptible Gas Transport[9]	7.55%	7.03%	5.48%	7.40%	6.04%	7.40%	6.04%
Total	100.00%	100.00%	100.00%	36.40%	28.61%	15.25%	11.99%

392. GP reasons that the above apportionment would facilitate several ratemaking goals, including "fairness of the specific rates in the apportionment of the total costs of service among the different consumers[.]"[693]

393. The DOC-DER analyzed the Company's proposed revenue responsibility apportionment by comparing the Company's current and proposed apportionment of revenue responsibility with the cost-based apportionment that was created by the Company's CCOSS. The Department sought to determine which classes are substantially below their respective costs of service and which classes are contributing revenues in excess of their cost of service (thus resulting in an inter-class subsidy).[694] The DOC-DER further reviewed the proposed increase for potential rate shock and the revenue contributions from customer classes with bypass options to ensure that the rates and revenue contributions remain competitive.[695]

394. The DOC-DER concluded that GP's proposed apportionment of revenue responsibility is reasonable because it "moves the majority of classes closer to the cost-based apportionment of revenue responsibility, while leaving the remaining classes very close to the status quo."[696]

---

[693] Ex. GP-25 at 17-18 (Hatzenbuhler Direct).
[694] Ex. DER-4 at 42-43 (Zajicek Direct).
[695] *Id*. at 43.
[696] *Id*. at 42, 47.

395. The DOC-DER further determined that GP's proposed revenue apportionment for interruptible customers was reasonable given that these customers have other fuel options available to them.[697]

396. Ultimately, the DOC-DER recommends that the Commission approve GP's proposed apportionment of revenue responsibility, and that if the Commission adopts a different revenue requirement, that the revenue requirement be apportioned among classes using GP's proposed apportionment percentages, as follows:[698]

Class	% Responsibility
Residential	15.71%
Firm General	12.53%
Interruptible Grain Drying	12.23%
Small Interruptible Gas Sales	2.53%
Small Interruptible Gas Transport	16.15%
Large Interruptible Gas Sales	0.44%
Large Interruptible Gas Transport	6.04%

397. The OAG does not take a position on the Company's proposed revenue allocation.[699]

398. The Administrative Law Judge concurs that GP's proposed apportionment of revenue responsibility is reasonable. The Judge also recommendations that the revenue requirement, if revised by the Commission, be apportioned consistent with the Company's proposal.

E. Basic Customer Service Charges

399. Customer bills generally contain two types of charges: a volumetric charge and a basic service change.[700] Both types of charges are used to cover the utility's costs in providing the services.[701]

400. The volumetric charge is a use charge that is based on the amount of natural gas consumed by the customer during the billing period.[702] Because customer

697 *Id*. at 46.
698 *Id*., Ex. DER-12 at 8 (Zajicek Surrebuttal).
699 Ex. OAG-2 at 2 (Lebens Surrebuttal).
700 *See* Ex. DER-3 at 5, SO-3 at 355 (Ouanes Direct)
701 *Id*.
702 *Id*.

usage varies month-to-month, the amount recovered through the volumetric charge fluctuates.[703]

401. Basic customer service charges, however, are a fixed charge and remain constant month-to-month.[704] In theory, the basic customer service charge recovers the utility's fixed costs that arise from making services available to the consumer.[705] These fixed costs include, for example, metering, reading, billing, collecting, and accounting, as well as costs associated with the capital investment in metering equipment and customer service connections.[706] When basic service charges are not enough to cover the utility's costs, the deficit is collected through volumetric charges.[707] In this way, higher-use customers not only pay for their own costs, but contribute to the extra costs attributable to lower-use consumers.[708]

402. GP proposes to increase the basic customer charge for all classes as follows:[709]

Summary of GP's Proposed Customer Service Charges by Customer Class[710]

Customer Class	Basic Customer Method CCOSS Customer Cost	Current Customer Charge	Proposed Customer Charge	Proposed Increase
Residential	$24.39	$7.50	$9.00	$1.50
Small Firm General Service	$27.62	$23.00	$27.50	$4.50
Large Firm General Service	$72.36	$28.50	$35.00	$6.50
Interruptible Grain Drying	$402.75	$145.00	$450.00	$350.00
Small Interruptible Sales	$151.69	$145.00	$150.00	$5.00
Small Interruptible Transport	$159.63	$200.00	$250.00	$50.00
Large Interruptible Sales	$509.38	$230.00	$500.00	$270.00
Large Interruptible Transport	$403.70	$260.00	$560.00	$300.00

703 *Id*.
704 *Id*.
705 *Id*.
706 Ex. DER-3 at SO-3 at 3 (Ouanes Direct).
707 Ex. DER-4 at 51-52 (Zajicek Direct).
708 *Id*. at 52.
709 *Id*. at 49 (citing information provided in Ex. GP-25 at 19-20 (Hatzenbuhler Direct) and Ex. GP-2 (Statement E, Rate Structure and Design, Schedule E-2a at 1-5) (Sept. 27, 2019)).
710 *Id*. at Table 6. Note that this table contains the average monthly customer service charges resulting from the daily charge for the applicable customer classes.

2. Residential and Firm Service Classes Basic Customer Charges

a. The Basic Customer Charge

403. GP proposes to increase the basic customer charge for the Residential customer class from $7.50 per month to $9.00 per month (a $1.50 increase per month); the Small Firm General Service class from $23.00 per month to $27.50 per month (a $4.50 increase per month); and the Large Firm General Service class from $28.50 per month to $35.00 per month (a 6.50 increase per month).[711]

404. GP reasoned that these increases would move the residential and firm general classes' basic customer charges closer to cost while not resulting in the rate shock that would accompany an increase in the basic customer charge if the CCOSS was fully applied.[712]

405. GP also purposes to move the residential and firm general classes from the current monthly basic customer charge to a daily basic customer charge.[713] The daily charge, however, is calculated such that the resulting average monthly customer charge is a round number that approximates a monthly basic customer charge.[714] In this way, the end cost for the customer and the actual revenue for the company is nearly identical, whether the charge is calculated on a daily or monthly basis.[715]

406. The DOC-DER evaluated GP's proposed service charges for all classes and determined that the allocation would reduce intra-class subsidies by moving the majority of classes, including the residential and firm general classes, closer to their cost of service, as identified in the CCOSS. As a result, the DOC-DER concluded that the Company's proposed increases to the residential and general firm customer classes were reasonable.[716]

407. The OAG disagreed. The OAH opposes any increase in the basic service charge for the residential and small firm general service classes.[717] The OAG takes no position on the increased basic service charges for the other six customers classes (large firm general service, interruptible grain drying, small interruptible sales, small interruptible transport, large interruptible sales, and large interruptible transport).[718]

408. The OAG articulated three reasons why the basic customer charge should not be increased: (1) it discourages conservation; (2) it disproportionately impacts low-

[711] Ex. GP-25 at 19 (Hatzenbuhler Direct).
[712] *Id*. at 20.
[713] Ex. DER-4 at 48-49 (Zajicek Direct).
[714] *Id*.
[715] *Id*. at 50-51.
[716] *Id*.
[717] Ex. OAG-1 at 7 (Lebens Direct).
[718] *See* Joint Issues Matrix at 8 (Apr. 10, 2020) (eDocket No.20203-161573-02).

usage users; and (3) it is inconsistent with monopoly regulation principles.[719] None of these claims were substantiated in the hearing record.

409. First, as both the DOC-DER and GP determined, the relatively small change in the basic service charge per month ($1.50 per month for residential users, $4.50 for small firm users, and $6.50 for large firm users) is not significant enough to realistically impact consumer energy conservation behavior. [720]

410. Second, the basic service charge accurately reflects fixed costs and decreases intra-class subsidies.[721] The OAG makes an assumption that low-income customers are also low-use customers who would benefit from costs being recovered on a volumetric basis.[722] Evidence, however, shows that low-income customers may actually use slightly more energy than average residential customers due to less access to energy efficient residences and appliances.[723] Thus, the proposed increase in the basic service charge could actually negatively impact low-income customers.[724]

411. Third, monopoly regulation is intended to prevent utilities from asserting monopoly power.[725] It is not intended to unreasonably restrict how utilities collect payment.[726] Moreover, fixed delivery charges are used by a variety of competitive market firms, such as furniture stores, hardware stores, and grocery stores, to collect fixed expenses.[727] In GP's case, the basic customer charge is intended to recover the fixed expenses associated with connecting the customer's access to safe, reliable service regardless of the amount of natural gas consumed.[728] Notably, the residential basic service charge is in line with the other four regulated case distribution utility companies serving Minnesota, which have residential basic service charges ranging from $8.50 to $9.50 per month.[729]

412. For these reasons, it is recommended that the Commission approve GP's proposed increases to the residential and general service customer classes.[730]

413. In sum, the Administrative Law Judge finds that GP's proposal to increase the basic customer charge for the residential class by $1.50 a month, the small firm general class by $4.50 a month, and the large firm general service class by $6.50 a

[719] Ex. OAG-1 at 3 (Lebens Direct).
[720] Ex. DER-8 at 2-3, 5-6 (Zajicek Rebuttal); Ex. GP-26 at 5-6 (Hatzenbuhler Rebuttal).
[721] Ex. DER-8 at 8-9 (Zajicek Rebuttal).
[722] *Id.*
[723] *Id.*
[724] *Id.*
[725] *Id.* at 6-8.
[726] *Id.*
[727] *Id.*
[728] *Id.*
[729] Ex. GP-26 at 8 (Hatzenbuhler Rebuttal).
[730] Ex. DER-8 at 9 (Zajicek Rebuttal).

month is reasonable because it will reduce intra-class subsidies while avoiding rate shock for customers.

b. Basic Customer Service Charge Billing Method

414. GP also proposes to change its basic customer service charge for the Residential and the two Firm General Service classes from a monthly fixed charge to a daily fixed charge.[731] In other words, instead of calculating the basic service charge on a monthly basis and billing the same amount each month, the Company proposes to calculate the charge on a daily basis, based upon a monthly fixed amount divided by the number of days in each month.

415. The Company reasons that charging the basic service charge on a daily basis would better match the way customers are billed and would account for customer cut-ins and cut-outs occurring outside the customer's normal billing cycle.[732] According to GP, the Company's bills for service outside a normal period are currently normalized, but that the customer cannot readily determine how the bill was calculated.[733] The Company further contends that the daily charge will allow customers to calculate their bills based on the number of days in each month and provides a "clearer" application of the customer charge.[734]

416. The DOC-DER disagreed with this proposal.[735] An accepted rate design principal is that rates should be understandable and easy to administer.[736] A monthly customer charge is simpler for customers to understand than a daily rate.[737] Moreover, the DOC-DER found that using both the daily and monthly calculation of the basic service charge produced nearly the exact same year-end revenue for the Company.[738]

417. For the reasons identified by the DOC-DER, the Administrative Law Judge concludes that a daily service charge would increase the complexity of customers' bills and the complexity for customers outweighs the benefits for the Company. Because the revenue results for the Company are nearly identical using either the daily or monthly calculation of the basic service charge, the Administrative Law Judge recommends that the Commission reject GP's proposal to change the basic service charge to a daily calculation and require the Company to continue with its current practice of applying the

[731] Ex. GP-32 at 3 (Bosch Rebuttal).
[732] Ex. GP-25 at 18-19 (Hatzenbuhler Direct).
[733] *Id*.
[734] *Id*.
[735] Ex. DER-4 at 50-51 (Zajicek Direct).
[736] *Id*. at 50.
[737] *Id*.
[738] *Id*. at 50-51. To determine the proposed rate, the Company chose to set a monthly rate and divided it by 365 days in a year, resulting the same final amount whether it is calculated on a monthly basis or a daily basis. *Id.* Consequently, whether the basic customer charge is billed on a daily or monthly basis, the final revenue amount is the same. *Id.*

charge on a monthly basis for the Residential, Small Firm General Service, and Large Firm General Service classes.

2. Large Interruptible Transportation Class and Interruptible Grain Drying Class Basic Customer Charges

418. GP proposed to increase the basic customer service charge for the Large Interruptible Transportation customer class from $260 per month to $560 per month, amounting to an increase of $300 per month.[739] The Company also proposed to increase the basic customer service charge for the Interruptible Grain Drying class from $145 per month to $450 per month, a $350 increase.[740]

419. The DOC-DER opined that the basic service charge for both the Large Interruptible Transportation class and the Interruptible Grain Drying class should both be set at $400 per month because these charges would more closely match the customer charges recommended by the CCOSS results.[741]

420. GP accepted the DOC-DER's recommendation that the basic customer charge for the Interruptible Grain Drying class be set at $400 per month.[742] The Company also does not oppose the DOC-DER's recommendation that the basic customer charge for the Large Interruptible Transport class be set at $400.[743]

421. GP and the DOC-DER further agreed that if the Commission adopts the recommended monthly basic service charge amount for the Large Interruptible Transportation class, then the Large Interruptible Sales class should be similarly adjusted to $355 per month to maintain the relationship between the Large Interruptible Sales class and the Large Interruptible Transport class.[744] (This would mean an increase in the Large Interruptible Sales class from the current $230 per month to $355 per month, instead of the $500 per month proposed by the Company.)[745]

422. While the hearing record is not clear as to why the parties selected these dollar values, having both classes move closer to cost at similar rates of increase is reasonable. Thus, the Administrative Law Judge adopts the parties' agreement in her recommendation.

---

[739] Ex. DER-4 at 49, Table 6 (Zajicek Direct).
[740] *Id*.
[741] *Id*. at 49, 53.
[742] Ex. GP-26 at 3 (Hatzenbuhler Rebuttal).
[743] Ex. GP-27 (Hatzenbuhler Testimony Summary).
[744] Ex. GP-26 at 4 (Hatzenbuhler Rebuttal); Ex. DER-12 at 6 (Zajicek Surrebuttal).
[745] Ex. GP-26 at 4 (Hatzenbuhler Rebuttal); Ex. DER-12 at 6 (Zajicek Surrebuttal). *Compare with* Ex. DER-4 at 49, Table 6 (Zajicek Direct).

3. Small Interruptible Class Basic Service Charge

423. The parties did not disagree as to GP's proposed basic service charge for the Small Interruptible Sales and Small Interruptible Transportation classes.[746]

424. The Company proposes a monthly customer service charge of $150 for the Small Interruptible Sales class (an increase of $5.00 per month) and $250 for the Small Interruptible Transport class (an increase of $50 per month).[747]

425. The Administrative Law Judge adopts the Company's proposed basic customer service charges for both of the Small Interruptible classes.

4. Summary of Recommendation on Basic Service Charges

426. For the reasons set forth above, the Administrative Law Judge recommends that the Commission approve the following monthly basic customer service charges for each of the Company's customer classes, all billed on a monthly basis:

Customer Class	Basic Customer Method CCOSS Customer Cost	Current Basic Service Charge	Recommended Basic Service Charge	Increase
Residential	$24.39	$7.50	$9.00	$1.50
Small Firm General Service	$27.62	$23.00	$27.50	$4.50
Large Firm General Service	$72.36	$28.50	$35.00	$6.50
Interruptible Grain Drying	$402.75	$145.00	$400.00	$255.00
Small Interruptible Sales	$151.69	$145.00	$150.00	$5.00
Small Interruptible Transport	$159.63	$200.00	$250.00	$50.00
Large Interruptible Sales	$509.38	$230.00	$355.00	$125.00
Large Interruptible Transport	$403.70	$260.00	$400.00	$140.00

F. Margin Sharing Proposal

427. In the Notice of and Order for Hearing, the Commission requested that the parties and the Administrative Law Judge develop a record on whether the proposed

[746] Joint Issues Matrix at 8 (Apr. 10, 2020) (eDocket No.20203-161573-02). Note that the OAG took no position on the basic customer charges for the Small Interruptible Sales and Small Interruptible Transportation classes.
[747] Ex. DOC-DER-4 at 49, Table 6 (Zajicek Direct); Ex. GP-25 at 19-20 (Hatzenbuhler Direct); Ex. GP-2 (Statement E, Rate Structure and Design, Schedule E-2a at 1-5) (Sept. 27, 2019).

margin sharing mechanism should be incorporated into the Revenue Decoupling Mechanism (RDM).[748]

428. GP proposes a margin sharing arrangement for a single Large Interruptible Transport class customer that represents a significant percentage (nine percent) of the Company's overall margin.[749]

429. GP's proposed margin sharing mechanism was developed by allocating the Company's revenue deficiency to the various customer classes with the resulting amounts allocated to the margin sharing customer set aside, and referred to as the "Target Margin Sharing Increase."[750] The Target Margin Sharing Increase was then allocated to the non-margin sharing customer classes.[751] Under the proposal, revenue would be collected from the margin sharing customer at the Large Interruptible Transport class rate and credited back to the other customers.[752]

430. GP explained that the purpose of this mechanism is to avoid the need for an immediate rate case in the event that the margin sharing customer ceases to take service.[753] Should the margin sharing customer cease service, the credit would no longer be applied to the other customers' bills.[754] To implement the margin sharing proposal, the Company proposed that it be incorporated into its RDM.[755]

431. The DOC-DER analyzed GP's margin sharing proposal and concluded that it was reasonable for several reasons. First, the proposal is symmetrical: in addition to bearing the risks, the other customers would enjoy a larger-than-proposed credit if the margin sharing customer increases usage above the level estimated in this proceeding.[756] Second, if the margin sharing customer does cease or reduce service, the margin sharing mechanism would allocate costs to other customers consistent with the rate design approved in this rate case.[757] Third, the proposal does not discriminate against other customer classes and could avoid the expenses of a new rate case.[758]

432. The DOC-DER, however, made three recommendations. First, the DOC-DER recommended that the Commission require GP to make an annual compliance filing each year showing the actual volumes purchased by the Interruptible Service class customer and its associated revenues; identifying the corresponding total credits; and describing the overall impact on customers. Second, the DOC-DER recommended the

---

[748] NOTICE AND ORDER FOR HEARING (Nov. 22, 2019) (eDocket No. 201911-157756-01).
[749] Ex. GP-31 at 10-11 (Bosch Direct).
[750] Ex. GP-25 at 14-15 (Hatzenbuhler Direct).
[751] *Id*.
[752] Ex. GP-25 at 15 (Hatzenbuhler Direct).
[753] *Id*.
[754] *Id*.
[755] Ex. GP-31 at 10-11 (Bosch Direct).
[756] Ex. DER-4 at 37 (Zajicek Direct).
[757] *Id*.
[758] *Id*. at 38.

imposition of a "sunset clause" on the mechanism, meaning that the revenue sharing mechanism be re-examined in the Company's next rate case or within five years after the Commission's order in this case, whichever occurs first.[759] Third, the DOC-DER recommended that the Company explain how the margin sharing mechanism would operate in the event the RDM did not continue beyond 2021.[760]

433. GP agreed to the compliance filing and sunset clause recommendations.[761] The Company also explained how the margin sharing mechanism could operate in the RDM's absence and by what authority the Commission could approve it.[762]

434. Based upon the recommendations of the DOC-DER and the agreements of the Company, the Administrative Law Judge recommends that the Commission: (1) approve the incorporation of GP's proposed margin sharing mechanism into the RDM; (2) require the Company to make an annual compliance filing, as described above; and (3) require that the revenue sharing mechanism be reviewed in the Company's next rate case or within five years from the Commission's order, whichever occurs first.

G. New Grain Drying Customer Class Rate Schedule

435. Interruptible Grain Drying customers of GP receive service under a separate tariff from the Company's other interruptible service customers.

436. GP proposes a new rate schedule applicable to the Interruptible Grain Drying customer class to reflect the unique operating characteristics of such customers: Grain Drying Rate 73.[763]

437. GP explained that grain drying customers are unique in that a customer typically has a season of operation with a varying start and stop to that season, coupled with potential seasons requiring varying levels of gas with which to dry their product.[764] This fluctuating start places an obligation on the grain drying customer to notify the Company prior to the start of its operations to ensure the Company is aware of the location of the facility, the expected hours of operation, and the customer's gas requirements.[765]

438. The DOC-DER did not oppose the new rate schedule and the OAG took no position on this issue.[766] Because GP's plan is reasonable and appropriate, the

[759] *Id*. at 38-40.
[760] *Id*.
[761] Ex. GP-32 at 5 (Bosch Rebuttal).
[762] *Id*. at 5-9.
[763] Ex. GP-31 at 8-9 (Bosch Direct).
[764] *Id*. at 9.
[765] *Id*.
[766] Joint Issues Matrix at 10 (Apr. 10, 2020) (eDocket No. 20203-161573-02).

Administrative Law Judge recommends that the Commission adopt the proposed Grain Drying Rate 73.

XIII. REVENUE DECOUPLING MECHANISM (RDM)

A. Introduction

439. Revenue decoupling is "a regulatory tool designed to separate a utility's revenue from changes in energy sales."[767] Its "purpose is to reduce a utility's disincentive to promote energy efficiency."[768] A revenue decoupling mechanism (RDM) allows the utility to recover differences between actual and forecasted base class revenue responsibility.[769]

440. The Commission first approved GP's RDM as a three-year pilot program in the Company's 2015 Rate Case.[770] The Company's RDM became effective on January 1, 2017.[771] Without Commission action, GP's RDM would have expired on December 31, 2020.[772] However, in 2019, the Company sought and obtained a one-year extension from the Commission.[773]

B. Revenue Decoupling Mechanism Extension

441. GP now proposes to extend its RDM pilot program indefinitely.[774] The Company reasons that continuation of the RDM better aligns its business objectives with state conservation goals and its customers' desires to use gas as efficiently as possible.[775] According to GP, the RDM also ensures that a general rate case will not be necessary as a result of continued conservation and efficiency; and helps to mitigate customer impact in the event of an abnormally cold heating season.[776]

442. The DOC-DER evaluated GP's RDM proposal and concluded that it is reasonable for the Commissioner to allow GP's RDM to continue through 2021 so that the Commission can base its decision on more Conservation Improvement Program (CIP) results.[777] The DOC-DER recommended that any extension decision should be made after December 31, 2021, to allow an evaluation of the Company's 2019 and

---

[767] Minn. Stat. § 216B.2412, subd. 2 (2018).
[768] *Id*.
[769] Ex. DER-5 at 2 (Davis Direct).
[770] GREAT PLAINS 2015 RATE CASE ORDER at 40–43, 56.
[771] *Id*.
[772] *Id*.
[773] *In the Matter of the Request of Great Plains Natural Gas Co., a Division of MDU Resources Group, Inc., for a One-Year Extension of Revenue Decoupling Pilot Program*, MPUC Docket No. G-004/M-19-198, ORDER at 1 (Jan. 13, 2020).
[774] Ex. GP-25 at 24 (Hatzenbuhler Direct).
[775] *Id*.
[776] *Id*.
[777] Ex. DER-5 at 18 (Davis Direct).

2020 CIP achievements.[778] The DOC-DER recommends against continuing the RDM indefinitely.[779]

443. Based upon GP's proposal and the need for additional performance data, the Administrative Law Judge recommends that Commission allow the Company's RDM to continue through 2021. After reviewing the Company's 2019 and 2020 CIP results, the Commission should make a final decision on whether to allow the RDM to continue or require it to end.

C. Removal of the Large Interruptible Class from RDM

444. As part of its RDM proposal, GP seeks to remove the Large Interruptible customer class from the RDM beginning in 2021.[780] The Company explained that it has only seven Large Interruptible Class customers and that a significant size disparity exists between the largest and smallest class members.[781] As a result, if a larger class member were to cease service, the RDM would have an "outsized" impact on the remaining small class members.[782]

445. GP further reasoned that a final decision in this case will be reached in 2020 and authorized volumes will be established in this record.[783] Thus, for the 2021 evaluation period, the RDM calculations will be "reset" to reflect the updated authorized volumes and margin-per-customer for each of the customer classes.[784] Consequently, 2021 would be the appropriate time to remove the Large Interruptible customers.[785]

446. The DOC-DER analyzed GP's proposal and concluded that removing customer classes with fewer than 50 customers from an RDM was reasonable to avoid a situation where one customer changing its operations could have a large impact on the other customers. The DOC-DER based its conclusion on three factors.[786] First, the DOC-DER consulted with a third-party expert who opined that a minimum threshold of 10 customers in a class should be applied when determining when to remove a class from the RDM.[787] Second, the OAG proposed a minimum threshold of 50 customers in

---

778 *Id*.
779 *Id*. at 19.
780 Ex. GP-25 at 24-26 (Hatzenbuhler Direct).
781 *Id*. at 25.
782 *Id*.
783 Ex. GP-26 at 11 (Hatzenbuhler Rebuttal).
784 *Id*.
785 *Id*.
786 Ex. DER-5 at 21-22 (Davis Direct); *see also 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-15-736 (MERC 2015 Rate Case), FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 45 (Oct. 31, 2016).
787 Ex. DER-5 at 21 (Davis Direct).

a fairly recent rate case (Minnesota Energy Resources Corporation's 2015 rate case).[788] Third, the Commission imposed a 50-customer threshold in that same case.[789]

447. The OAG took no position on whether to allow the Company to remove the Large Interruptible customers from the RDM in this case.[790]

448. Based upon the rationale announced in the 2015 Minnesota Energy Resources Corporation rate case, the Administrative Law Judge recommends that the Commission allow GP to remove the Large Interruptible customer class from the RDM beginning in 2021.

D. Minimum Savings Threshold

449. The Notice of and Order for Hearing in this case directs the parties to consider whether a minimum energy savings level should be required in order to implement an RDM surcharge.[791]

450. GP cited three reasons that RDM surcharges should not be directly connected to minimum energy savings. First, the Company suggested that its energy savings are affected by factors outside of its control, such as agriculture and commodity pricing, new customer growth, and the magnitude of customer projects on the Company's energy savings results.[792] Second, GP believes that "[m]aking the end result, achievement of the goal, a prerequisite to being allowed to administer one of the tools put in place specifically to help achieve that goal is backwards."[793] Third, the Company believes the surcharge restriction penalizes GP because the minimum savings threshold "only limits the ability to surcharge customers and not the ability to refund[.]"[794]

451. The DOC-DER agreed with the Company's conclusion that it was not necessary for the Commission to impose a minimum energy savings threshold as this time. The Department reasoned that the Commission will have an opportunity to consider the minimum savings issue again in 2021, when it determines whether to continue the RDM going forward. Additionally, the Department noted that the Commission had declined to impose minimum savings thresholds in past rate cases.[795]

---

[788] *See 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-15-736 (MERC 2015 Rate Case), FINDINGS OF FACT, CONCLUSIONS, AND ORDER at 45 (Oct. 31, 2016).
[789] *Id.* at 43-47, 57.
[790] Joint Issues Matrix (Apr. 10, 2020) (eDocket No. 20203-161573-02).
[791] NOTICE OF AND ORDER FOR HEARING at 2 (Nov. 22, 2019) (eDocket No. 201911-157756-01).
[792] Ex. GP-25 at 27 (Hatzenbuhler Direct).
[793] Ex. GP-26 at 12 (Hatzenbuhler Rebuttal).
[794] Ex. GP-25 at 27 (Hatzenbuhler Direct).
[795] Ex. DER-5 at 19-20 (Davis Direct).

452. However, in the event the Commission chooses to implement a minimum savings threshold, the Department stated that a minimum savings threshold of 13,000 dekatherms would be reasonable because it is "4 percent lower than the lowest level of energy savings Great Plains achieved between 2013 and 2018."[796] GP concurred that if a minimum energy-savings threshold were to be set prior to the Commission's evaluation of whether GP's RDM should continue beyond 2021, it should be no more than 13,000 Dk.[797]

453. The Administrative Law Judge, therefore, recommends that a minimum savings threshold should not be imposed at this time.

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

CONCLUSIONS OF LAW

1. The Minnesota Public Utilities Commission and the Administrative Law Judge have jurisdiction to consider this matter pursuant to Minn. Stat. § 14.50 and Minn. Stat. §§ 216B.08, .09, .15, and .16 (2018).

2. The public and the parties received proper and timely notice of the requested rate increase, the public and evidentiary hearings, and the public comment period.

3. GP has provided all information required by Minn. R. Part 7825.

4. GP complied with all procedural requirements of statute and rule.

5. Minnesota law proclaims that public utilities shall be regulated:

> . . . in order to provide the retail consumers of natural gas and electric service in this state with adequate and reliable services at reasonable rates, consistent with the financial and economic requirements of public utilities and their need to construct facilities to provide such services or to otherwise obtain energy supplies, to avoid unnecessary duplication of facilities which increase the cost of service to the consumer and to minimize disputes between public utilities which may result in inconvenience or diminish efficiency in service to the consumers.[798]

6. Every rate made, demanded, or received by any public utility shall be just and reasonable.[799] Rates shall not be unreasonably preferential, unreasonably prejudicial, or discriminatory, but rather, shall be sufficient, equitable, and consistent in

[796] *Id*. at 20.
[797] Ex. GP-29 at 3-4 (Fischer Rebuttal).
[798] Minn. Stat. § 216B.01 (2018).
[799] Minn. Stat. § 216B.03.

application to a class of consumers.[800] In addition, to the maximum reasonable extent, the commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of Minn. Stat. §§ 216B.164, 216B.241, and 216C.05.[801]

7. The burden of proof is on the public utility to show that a rate change is just and reasonable.[802] Any doubt as to reasonableness should be resolved in favor of the consumer.[803]

8. When determining the just and reasonable rates for public utilities, Minn Stat. 216B.16, subd. 6 (2018) directs the Commission to give due consideration to

> (1) the public need for adequate, efficient, and reasonable service;
>
> (2) 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,
>
> (3) the need of the public utility to earn a fair and reasonable return upon the investment in such property.

9. In determining the rate base upon which the utility is to be allowed to earn a fair rate of return, the Commission shall give due consideration:

> (a) to evidence of the cost of the property when first devoted to public use;
>
> (b) to prudent acquisition cost to the public utility less appropriate depreciation on each,
>
> (c) to construction work in progress,
>
> (d) to offsets in the nature of capital provided by sources other than the investors, and,
>
> (e) to other expenses of a capital nature.[804]

---

[800] *Id.*
[801] *Id.*
[802] Minn. Stat. § 216B.16, subd. 4.
[803] Minn. Stat. § 216B.03.
[804] Minn. Stat. § 216B.16, subd. 6.

10. For purposes of determining rate base, the commission shall consider the original cost of utility property included in the base and shall make no allowance for its estimated current replacement value.[805]

11. The record supports the resolution of the settled, resolved, and uncontested matters set forth in this Report. These matters have been resolved in the public interest and are supported by substantial evidence, as required by Minn. Stat. § 216B.16, subd. 1a (2018).

12. Rates set in accordance with this Report would be just and reasonable.

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

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

RECOMMENDATION

The Administrative Law Judge recommends that the Commission:

1. Approve a rate increase in accordance with the terms of this Report.

2. Incorporate the agreements made by the parties in the course of this proceeding into its Order.

3. Adopt the recommendations set forth in the Findings of Fact above.

4. Require GP to make further compliance filings as recommended herein.

5. Allow GP's RDM to continue through 2021; approve the incorporation of GP's proposed margin sharing mechanism into the RDM; require the Company to make an annual compliance filing; and require that the revenue sharing mechanism be reviewed in the Company's next rate case or within five years from the Commission's order, whichever occurs first.

6. Not impose a minimum savings threshold at this time.

7. Accept, as reasonable, GP's sales forecast for the test year.

[805] *Id.*

8. Use the Company's proposed CIP expense of $566,621 as the basis for its CCRA rate and require that any changes to the CCRA factor be determined in the Company's next annual CIP tracker and financial incentive proceeding.

Dated: June 30, 2020

ANN C. O'REILLY
Administrative Law Judge

NOTICE

Exceptions to this Report, if any, by any party adversely affected, must be filed under the timeframes established in the Commission's rules of practice and procedure, Minn. R. 7829.2700, .3100 (2019), unless otherwise directed by the Commission. Exceptions should be specific and numbered separately. Oral argument before a majority of the Commission will be permitted pursuant to Minn. R. 7829.2700, subp. 3 (2019). The Commission may, at its own discretion, accept, modify, or reject the Administrative Law Judge's recommendations.

MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS

PO Box 64620
Saint Paul, MN 55164-0620
mn.gov/oah

PH (651) 361-7900
TTY (651) 361-7878
FAX (651) 539-0310

June 30, 2020

See Attached Service List

Re: ***In the Matter of the Petition by Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities, Co., for Authority to Increase Natural Gas Rates in Minnesota***
OAH 65-2500-36528
MPUC G-004/CR-19-511

To All Persons on the Attached Service List:

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

If you have any questions, please contact me at (651) 361-7888, lisa.armstrong@state.mn.us, or via facsimile at (651) 539-0310.

Sincerely,

Lisa Armstrong

LISA ARMSTRONG
Legal Assistant

Enclosure

cc: Docket Coordinator

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

CERTIFICATE OF SERVICE

In the Matter of the Petition by Great Plains Natural Gas Co., a Division of Montana-Dakota Utilities, Co., for Authority to Increase Natural Gas Rates in Minnesota	OAH Docket No.: 65-2500-36528 MPUC No.: G-004/CR-19-511

Lisa Armstrong certifies that on June 30, 2020, she served the true and correct **FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDATION** by eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

eService, and U.S. Mail, (in the manner indicated below) to the following individuals:

First Name	Last Name	Email	Company Name
Tamie A.	Aberle	tamie.aberle@mdu.com	Great Plains Natural Gas Co.
Jorge	Alonso	jorge.alonso@state.mn.us	Public Utilities Commission
Peter	Beithon	pbeithon@otpco.com	Otter Tail Power Company
Kristin	Berkland	kristin.berkland@ag.state.mn.us	Office of the Attorney General-RUD
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP
Ann	O'Reilly	ann.oreilly@state.mn.us	Office of Administrative Hearings
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD
Peter	Scholtz	peter.scholtz@ag.state.mn.us	Office of the Attorney General-RUD
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy