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File #: 203590

August 28, 2024

VIA EMAIL

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
P.O. Box 3265
Harrisburg, PA 17105-3265

Re: Pa. PUC, *et al.* v. Columbia Gas of Pennsylvania, Inc.
Docket No. R-2024-3046519

Dear Secretary Chiavetta:

Attached please find the corrected Joint Petition for Settlement ("Settlement") on behalf of Columbia Gas of Pennsylvania, Inc., which was recently filed in the above-referenced proceeding. The prior version contained duplicate numbering of Paragraphs 37 through 39 of the Settlement.

Specifically, the following changes have been made:

- The Paragraph numbers in Sections III.D through V on Pages 9 through 13 of the Settlement have been corrected to be Paragraphs 40 through 63 of the Settlement.

Copies will be provided as indicated on the Certificate of Service.

Sincerely yours,

Megan E. Rulli

MER/kls
Attachment

cc: Rosemary Chiavetta, Secretary (*letter and Certificate of Service only*)
Certificate of Service

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served upon the following persons, in the manner indicated, in accordance with the requirements of § 1.54 (relating to service by a participant).

VIA E-MAIL ONLY

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Dated: August 28, 2024

Megan E. Rulli

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket No.	R-2024-3046519
Office of Small Business Advocate	:		C-2024-3047905
Office of Consumer Advocate	:		C-2024-3047675
Ronald T. Bernick	:		C-2024-3048339
Linda Allison	:		C-2024-3048588
Philip Bloch	:		C-2024-3048478
Pennsylvania State University	:		C-2024-3048624
Daniel E. Skvarla	:		C-2024-3049677
	:		
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		

JOINT PETITION FOR SETTLEMENT

TO ADMINISTRATIVE LAW JUDGE JEFFREY A. WATSON:

I. INTRODUCTION

The Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Small Business Advocate ("OSBA"), the Office of Consumer Advocate ("OCA"), The Pennsylvania State University ("PSU"), and Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"), parties to the above-captioned proceedings (hereinafter collectively referred to as the "Joint Petitioners"), hereby join in this Joint Petition for Settlement ("Settlement") and respectfully request that Administrative Law Judge Jeffrey A. Watson ("ALJ Watson" or the "ALJ") and the Commission expeditiously approve the Settlement as set forth below. In addition, the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") and the Pennsylvania Weatherization Providers Task Force, Inc. ("PA Task Force") do not oppose the Partial Settlement.

As fully set forth and explained below, the Joint Petitioners have agreed to a settlement of all issues among them, exclusive of the Company's proposed Municipal Levelization Charge, in the above-captioned general base rate proceeding (the "2024 Base Rate Filing"). Among other provisions, the Settlement provides for increases in rates designed to produce $74.0 million in additional annual base rate revenue based upon the pro forma level of operations for the twelve months ended December 31, 2025. In support of the Settlement, the Joint Petitioners state the following:

II. BACKGROUND

1. Columbia is a "public utility" and "natural gas distribution company" ("NGDC") as those terms are defined in Sections 102 and 2202 of the Public Utility Code, 66 Pa.C.S. §§ 102, 2202. Columbia provides natural gas distribution, sales, transportation, and/or supplier of last resort services to approximately 445,000 retail customers in portions of 26 counties of Pennsylvania.

2. On March 15, 2024, Columbia filed with the Commission Supplement No. 374 to its Tariff Gas – Pa. P.U.C. No. 9 ("Supplement No. 374" or "base rate filing"). Supplement No. 374, issued March 15, 2024, and to be effective May 14, 2024, proposed an increase in annual revenues of approximately $124.1 million based upon a pro forma fully projected future test year ("FPFTY") ending December 31, 2025. The filing was made in compliance with the Commission's regulations, and contained all supporting data and testimony required to be submitted in conjunction with a tariff change seeking a general rate increase.

3. On April 4, 2024, the Commission issued an Order initiating an investigation of Columbia's proposed general rate increase and suspending Columbia's Supplement No. 374 until December 14, 2024, unless otherwise directed by Order of the Commission.

4. On April 5, 2024, Columbia filed Supplement No. 380 to Tariff Gas Pa. PUC No. 9, suspending Columbia's Supplement No. 374 until December 14, 2024.

5. Formal Complaints were filed on behalf of the OCA (C-2024-3047675), OSBA (C-2024-3047905), Ronald T. Bernick (C-2024-3048339), Linda Allison (C-2024-3048588), Philip Bloch (C-2024-3048478), PSU (C-2024-3048624), and Daniel E. Skvarla (C-2024-3049677).

6. PA Task Force and CAUSE-PA filed Petitions to Intervene.

7. I&E filed a Notice of Appearance.

8. A Prehearing Conference was scheduled for April 17, 2024. Parties who participated in the prehearing conference filed prehearing memoranda identifying potential issues and witnesses.

9. The initial Prehearing Conference was held as scheduled on April 17, 2024. At the prehearing conference, the ALJ established the litigation schedule. The ALJ also set forth discovery rules, which, pursuant to the parties' agreement, included shorter response times than those provided in the Commission's regulations. *See* 52 Pa. Code §§ 5.341 *et seq.*

10. On April 18, 2024, the ALJ issued a Prehearing Order that confirmed the litigation schedule established at the Prehearing Conference and granted the Petitions to Intervene of PA Task Force and CAUSE-PA.

11. Public Input hearings were held on May 21 and May 22, 2024.

12. On June 20, 2024, Columbia filed a Motion for a Protective Order. The ALJ granted Columbia's Motion and issued the Protective Order on July 17, 2024.

13. The Joint Petitioners conducted substantial formal and informal discovery in this proceeding. In accordance with the litigation schedule, various parties filed direct, rebuttal, surrebuttal and rejoinder testimony.

14. An evidentiary hearing was held on August 1, 2024, for the purpose of admitting all parties' evidence into the record.

15. The Parties held numerous settlement discussions over the course of this proceeding. As a result of those discussions and the efforts of the Joint Petitioners to examine the issues in the proceeding, the Joint Petitioners were able to advise the ALJ that a settlement in principle was achieved.

16. The Joint Petitioners have agreed to a base rate increase, the allocation of revenues and rate design to recover that increase, as well as other issues that were raised in this proceeding, excluding Columbia's proposal to institute a Municipal Levelization Charge. In the Settlement, the Joint Petitioners have proposed that rates be designed to produce an additional $74.0 million in annual base rate operating revenues instead of the Company's filed increase request of approximately $124.1 million.

17. In light of the settlement in principle reached, on August 14, 2024, the ALJ issued a Second Interim Order Setting Various Deadlines and Procedures for Post Hearing Filings, which extended the due date for the Settlement Petition and any Main Briefs until 4:00 PM on August 22, 2024.

18. On August 21, 2024, the ALJ issued a Third Interim Order Setting Various Deadlines and Procedures for Post Hearing Filings, which extended the deadline for filing Statements in Support of the Settlement until August 30, 2024.

19. The Settlement terms are set forth in the following Section III.

III. <u>SETTLEMENT</u>

20. The following terms of this Settlement reflect a carefully balanced compromise of the interests of all the Joint Petitioners in this proceeding. The Joint Petitioners unanimously agree that the Settlement is in the public interest. The Joint Petitioners respectfully request that the 2024

Base Rate Filing, including those tariff changes included in Supplement No. 374 and specifically identified in Appendix "A" attached hereto, be approved subject to the terms and conditions of this Settlement specified below:

A. REVENUE REQUIREMENT

21. Rates will be designed to produce an increase in annual operating revenues of $74.0 million over current base rates based upon the pro forma level of operations for the twelve months ended December 31, 2025.

22. The state income tax rate in this proceeding will be set at 7.99% and has been reflected in the settlement revenue requirement. The Company will reflect subsequent state tax adjustments to the state income tax rate for the post-2025 tax years through the Company's State Tax Adjustment Surcharge, currently Tariff Gas – Pa. P.U.C. No. 9, page 165, or future base rate proceedings.

23. As of the effective date of rates in this proceeding, Columbia will be eligible to include plant additions in the Distribution System Improvement Charge ("DSIC") at the later of (1) the end of the FPFTY or (2) once the total FPFTY account balances exceeds $4,815,151,833 as projected by Columbia at December 31, 2025 per Columbia Exhibit No. 108, Schedule 1. The foregoing provision is included solely for purposes of calculating the DSIC and is not determinative for future ratemaking purposes of the projected additions to be included in rate base in a FPFTY filing.

24. For purposes of calculating its DSIC, Columbia shall use the equity return rate for gas utilities contained in the Commission's most recent Quarterly Report on the Earnings of Jurisdictional Utilities and shall update the equity return rate each quarter consistent with any changes to the equity return rate for gas utilities contained in the most recent Quarterly Earnings

Report, consistent with 66 Pa. C.S. § 1357(b)(3), until such time as the DSIC is reset pursuant to the provisions of 66 Pa. C.S. § 1358(b)(1).

25. Columbia will be permitted to continue to use normalization accounting with respect to the benefits of the tax repairs deduction.

26. Columbia also will be permitted to continue to use normalization accounting with respect to the tax treatment of Section 263A mixed service costs.

27. Columbia will be permitted to recover the amortization of costs related to the following:

(i) Blackhawk Storage – Continuation of the previously-approved 24.5 year amortization of the total amount of $398,865 to be included on books and in rate base as a regulatory asset to reflect the total original cost that began on October 28, 2008.

(ii) Pension Prepayment – Continuation of the previously-approved ten-year amortization of $8,449,772.00 that began December 16, 2018.

(iii) COVID-19 Related Uncollectible Accounts Expense – Continuation of the previously-approved 4-year amortization of $2,832,363 that began December 17, 2022.

28. As established in the settlement of Columbia's base rate proceeding at R-2012-2321748, Columbia will be permitted to continue to defer the difference between the annual OPEB expense calculated pursuant to FASB Accounting Standards Codification ("ASC") 715, "Compensation – Retirement Benefits (SFAS No. 106) and the annual OPEB expense allowance in rates of $0. Only those amounts attributable to operation and maintenance would be deferred and recognized as a regulatory asset or liability. To the extent the cumulative balance recorded

reflects a regulatory asset, such amount will be collected from customers in the next base rate proceeding over a period to be determined in that rate proceeding. To the extent the cumulative balance recorded reflects a regulatory liability, there will be no amortization of the (non-cash) negative expense and the cumulative balance will continue to be maintained.

29. Commencing with the effective date of rates, Columbia will deposit amounts in the OPEB trusts when the cumulative gross annual accruals calculated by its actuary pursuant to ASC 715 are greater than $0. If annual amounts deposited into OPEB trusts, pursuant to this Partial Settlement, exceed allowable income tax deduction limits, any income taxes paid will be recorded as negative deferred income taxes, to be added to rate base in future proceedings.

30. On or before April 1, 2025, Columbia will provide I&E, OCA and OSBA an update to Columbia Exhibit No. 108, Schedule 1, which will include actual capital expenditures, plant additions, and retirements by month for the twelve months ending December 31, 2024. On or before April 1, 2026, Columbia will update Exhibit No. 108, Schedule 1 filed in this proceeding for the twelve months ending December 31, 2025. In Columbia's next base rate proceeding, the Company will prepare a comparison of its actual revenue, expenses and rate base additions for the twelve months ended December 31, 2025. However, it is recognized by the Joint Petitioners that this is a black box settlement that is a compromise of Joint Petitioners' positions on various issues.

31. Tariff rates will go into effect on December 14, 2024.

32. For purposes of this settlement, Columbia's as-filed depreciation and amortization rates will be utilized. The parties to this proceeding continue to disagree about the appropriate depreciation method to be used by Columbia, and this settlement should not be construed as agreement to the methodology. All parties reserve their respective rights to address the depreciation methodology in any future base rate proceeding.

33. The Company agrees to file a cash working capital study in its first rate case filed after January 1, 2026. All parties reserve their respective rights to present any position on the treatment of the results of such study.

34. The proposed IT transformation ("WAM") plan and schedule, as well as the allocation of costs thereof to Columbia, are accepted.

B. ALTERNATIVE RATEMAKING

35. Columbia's Pilot Weather Normalization Adjustment ("WNA") mechanism will continue until a final order is entered in the Company's first rate case filed after December 14, 2024, which is the end of the suspension period for the general rate increase filing in this docket, pursuant to the terms of the Commission-approved settlement at Docket No. R-2021-3024296, and as further modified herein. For informational purposes, the Company shall continue to maintain and provide to the OCA, I&E and OSBA by October 1 of each year all reports and records supporting the operation of its WNA for the preceding year, including the Company's monthly computation of the WNA and all data underlying the Company's monthly WNA computation. All parties reserve their respective rights to propose or oppose a WNA in a future base rate proceeding.

36. Columbia's Revenue Normalization Adjustment ("RNA") proposal is withdrawn without prejudice.

C. REVENUE ALLOCATION AND RATE DESIGN

37. Class revenue allocation will be approximately as shown in Appendix "B". Rate design for all classes shall be as shown in Appendix "C". Revenue allocation and rate design reflect a compromise and do not endorse any particular cost of service study.

38. The Residential customer charge will be set at $17.25 per month.

39. Columbia's proposed Municipal Levelization Charge is reserved for briefing.

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D. ENERGY EFFICIENCY AND CONSERVATION ("EE&C")

40. The updates to Columbia's Three-Year Energy Efficiency Plan ("EE Plan"), as described in the direct testimony of Theodore M. Love, are accepted.

E. UNIVERSAL SERVICE ISSUES

41. Columbia will work with its Universal Service Advisory Committee ("USAC") to develop a plain language notice, on a pilot basis, of the right to enter Customer Assistance Program ("CAP") and the arrearage forgiveness benefits of CAP, to be provided to confirmed low-income customers with arrears of at least $300. The Company may recover the costs of the pilot notice through its Universal Services Rider. Columbia will report the results and costs of the pilot in its next Universal Service and Energy Conservation Plan ("USECP") filing.

42. Columbia will work with its USAC to develop a plain language notice, on a pilot basis, of the right to enroll in CAP when a security deposit is waived or refunded pursuant to 66 Pa. C.S. § 1404(a.1) and 52 Pa. Code § 56.32(e). The Company may recover the costs thereof through its Universal Services Rider. Columbia will report the results and costs of the pilot in its next USECP filing.

43. Columbia will work with its USAC to develop a plain language notice, on a pilot basis, to customers at or below 150% of the FPL when negotiating a payment arrangement. The Company may recover the costs thereof through its Universal Services Rider. Columbia will report the results and costs of the pilot in its next USECP filing.

44. Columbia will work with its USAC to develop a plain language notice, on a pilot basis, to customers who have had service disconnected for nonpayment, and who remain disconnected at the time of the Company's Cold Weather Survey ("CWS") undertaken for the PUC. The Company may recover the costs thereof through its Universal Services Rider. Columbia will report the results and costs of the pilot in its next USECP filing.

45. Columbia will present a pilot program involving the use of speech analytics no later than the Company's next USECP review or base rate proceeding, whichever comes first. As discussed in the Direct Testimony of OCA witness Colton, the Company will include the USAC in the development of the speech analytics pilot. The Company may recover the costs thereof through its Universal Services Rider.

46. The Company will amend its Tariff language regarding security deposits (Section 6.2(1)) to state: "A Customer or Applicant that provides self-certification or other income documentation that household income is at or below 150% of the federal poverty level shall not be asked to provide a cash deposit."

47. Columbia will report at each USAC meeting for at least three years, or until the final decision in its next base rate case, whichever is longer, the number of customers with waived or refunded security deposits.

48. The Company will review with its USAC call scripting and checklists for its Customer Service Representatives ("CSR") to assist in screening customers for eligibility and refer low-income customers to available assistance programs, including CAP, before placing customers on a payment arrangement.

49. The costs of implementing the above-actions related to confirmed and low-income customers will be recoverable through the Universal Service rider.

50. The Company will increase its Low Income Usage Reduction Program ("LIURP") annual budget by $800,000 beginning in 2026. All parties reserve their respective rights to propose an appropriate budget amount for LIURP in any future rate case proceeding or other appropriate proceeding.

F. MISCELLANEOUS ISSUES

51. Columbia will implement a process to initiate an email to an existing customer, if an existing email is available, upon any request to start or transfer gas service of an active account into another name. The Company will work with PSU to implement comments on PSU's accounts.

52. Other issues raised by other parties are withdrawn, without prejudice.

IV. SETTLEMENT IS IN THE PUBLIC INTEREST

53. This Settlement was achieved by the Joint Petitioners after an extensive investigation of Columbia's filing, including informal and formal discovery and the submission of direct, rebuttal, surrebuttal and rejoinder testimony by a number of the Joint Petitioners that were admitted into the record by stipulation.

54. Acceptance of the Settlement will avoid the necessity of further administrative and possibly appellate proceedings regarding the settled issues at what would have been a substantial cost to the Joint Petitioners and Columbia's customers.

55. The Joint Petitioners will submit their respective Statements in Support setting forth the basis upon which each believes the Settlement to be fair, just and reasonable and therefore in the public interest by August 30, 2024. The Joint Petitioners' Statements in Support will be designated as Appendices "E" through "I," with Appendix J containing any Letter(s) of non-opposition to the Partial Settlement.

V. CONDITIONS OF SETTLEMENT

56. This Settlement is conditioned upon the Commission's approval of the terms and conditions contained herein without modification. If the Commission modifies the Settlement, then any Joint Petitioner may elect to withdraw from this Settlement and may proceed with litigation and, in such event, this Settlement shall be void and of no effect. Such election to withdraw must be made in writing, filed with the Secretary of the Commission and served upon

all Joint Petitioners within five (5) business days after the entry of any Order modifying the Settlement.

57. The Joint Petitioners acknowledge and agree that this Settlement, if approved, shall have the same force and effect as if the Joint Petitioners had fully litigated these proceedings resulting in the establishment of rates that are Commission-made, just and reasonable rates.

58. This Settlement and its terms and conditions may not be cited as precedent in any future proceeding, except to the extent required to implement this Settlement.

59. The Commission's approval of the Settlement shall not be construed to represent approval of any Joint Petitioner's position on any issue, except to the extent required to effectuate the terms and agreements of the Settlement in these and future proceedings involving Columbia.

60. It is understood and agreed among the Joint Petitioners that the Settlement is the result of compromise and does not necessarily represent the position(s) that would be advanced by any Joint Petitioner in these proceedings if they were fully litigated.

61. This Settlement is being presented only in the context of these proceedings in an effort to resolve the proceedings in a manner that is fair and reasonable. The Settlement is the product of compromise between and among the Joint Petitioners. This Settlement is presented without prejudice to any position that any of the Joint Petitioners may have advanced and without prejudice to the position any of the Joint Petitioners may advance in the future on the merits of the issues in future proceedings except to the extent necessary to effectuate the terms and conditions of this Settlement. This Settlement does not preclude the Joint Petitioners from taking other positions in proceedings involving other public utilities under Section 1308 of the Public Utility Code, 66 Pa.C.S. § 1308, or any other proceeding.

62. The Joint Petitioners recognize that the proposed Settlement does not bind Formal Complainants that do not choose to join herein. A copy of the proposed Settlement and attached Appendices hereto, including Statements in Support, are simultaneously being served upon all Formal Complainants in this proceeding.

63. If the ALJ adopts the Settlement without modification, the Joint Petitioners waive their individual rights to file exceptions with regard to the Settlement. Joint Petitioners retain their rights to file briefs, exceptions and replies to exceptions with respect to the issue that is reserved for litigation.

VI. CONCLUSION

WHEREFORE, the Joint Petitioners, by their respective counsel, respectfully request as follows:

1. That the Honorable Administrative Law Judge Jeffrey A. Watson and the Commission approve this Settlement including all terms and conditions thereof, without modification;

2. That the Commission's investigation at Commission Docket R-2024-3046519, and the Complaints of the OCA (C-2024-3047675), OSBA (C-2024-3047905), Ronald T. Bernick (C-2024-3048339), Linda Allison (C-2024-3048588), Philip Bloch (C-2024-3048478, PSU (C-2024-3048624), and Daniel E. Skvarla (C-2024-3049677) be marked closed.

3. That the Commission enter an Order ruling on the issue reserved for litigation.

4. That the Commission enter an Order authorizing Columbia Gas of Pennsylvania, Inc. to file a tariff or tariff supplement in compliance with the Commission's Order, effective for service rendered on and after December 14, 2024.

Respectfully submitted,

Michael W. Hassell

Dated: August 22, 2024

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Melanie El Atieh ______________________________ Dated: August 22, 2024
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/s/ Steven C. Gray

_______________________________ Dated: August 22, 2024

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APPENDIX A

RULES AND REGULATIONS GOVERNING THE DISTRIBUTION AND SALE OF GAS (Continued)

8. Extensions

8.1 Residential Service Connections (C)

The Company will install the service line from its main to point of delivery, as defined in the Point of Delivery section of this tariff; provided, however;

(a) In the territories formerly served under Tariff Gas--Pa. P.U.C. No. 6 and Tariff Gas--Pa. P.U.C. No. 7, the Company will install at its expense the service line from its main to a convenient point approximately one-hundred fifty (150) feet inside the customer's property line, absent any abnormal underground conditions or excessive permitting requirements. (See the description of Territory section of this tariff to identify territory formerly served under Tariff Gas--Pa. P.U.C. No. 6 and Tariff Gas--Pa. P.U.C. No. 7.)

(b) In rural areas, where service is not available directly from the Company, service may be provided from a transmission or production line. It is the sole discretion of the owner of the transmission or production line to allow service from their facilities to the customer. If connection is allowed, the Company's service connection will consist of a tap on the line and a service valve.

8.2 Capital Expenditure Policy

8.2.1 Residential Distribution Service

The Company, at its discretion, may extend its distribution mains up to a distance of one-hundred fifty (150) feet on any street or highway without cost to an applicant(s), absent any abnormal underground conditions or unusual permitting requirements. When abnormal underground conditions or unusual permitting requirements exist, as determined by the Company, the applicant(s) will be required to pay a refundable cash deposit in an amount determined by the Company.

The applicant(s) will be required to pay a cash deposit to the Company when it is necessary to extend the main line more than one-hundred fifty (150) feet per applicant. The cash deposit will be equal to the difference between the minimum capital investment required to serve the applicant(s)'s gas requirements, excluding the one-hundred fifty (150) foot main allotment per applicant, and the amount of capital that the Company can justify investing in the project, based on the anticipated gas requirements of the applicant(s). The minimum capital investment is the capital expenditure required to serve only the gas requirements requested by the particular applicant(s).

The maximum allowable investment is the amount of capital expenditure which the estimated revenues generated from a proposed project would support and still provide the necessary return to the Company, taking into consideration the estimated additional annual quantities, rate schedule, cost of gas, operating and maintenance expense, interest and taxes.
If the net present value of the project is greater than $1,000 per applicant, the Company may, at its sole discretion, provide a contribution up to $1,000 per applicant, to offset installation costs of gas piping incurred by the applicant(s).

(C) Indicates Change

RATE DGDS - DISTRIBUTED GENERATION DISTRIBUTION SERVICE

APPLICABILITY

Throughout the territory served under this Tariff.

AVAILABILITY

Available, at one location, for the distribution requirements of any commercial or industrial customer using distributed generation equipment such as reciprocating engines, gas turbines, microturbines, and fuel cells used for electrical power generation. Service is available when such customer executes a contract with the Company for a period mutually agreed to between the Company and the customer for distribution service in accordance with all terms and conditions of such contract, provided that the Company's facilities are adequate to provide the requested service.

Service under this rate schedule shall not be available to a single customer who is a Priority 1 Customer, as defined in the Service Limitations section of this Tariff, unless such customer also contracts for firm service under Rate SS-Standby Service at a level necessary to meet the portion of daily and seasonal requirements of the facility not covered by installed operable alternative fuel capability.

CHARACTER OF SERVICE

Service furnished pursuant to this rate schedule shall be subject to termination at the Company's discretion based on its inability to distribute such natural gas. The Company may decline to serve a qualified distribution customer if, in the Company's sole discretion, continuation or initiation of distribution service will jeopardize the supply of gas to the Company's firm customers. If service is terminated under this schedule, the Company will attempt to provide service to a customer under an otherwise applicable rate schedule. In the event of termination, the Company will notify the customer as soon as possible.

A Distributed Generation Distribution Service account may be returned to the applicable Sales Service rate if, for a period of at least five (5) consecutive days in one billing cycle, the Company:

(1) has not received gas supply for the account;
(2) the account's bank balance is insufficient to cover the consumption or the customer did not have access to its bank balance due to the issuance of an OFO and/or OMO; and
(3) the customer consumed gas on one or more days during such five (5) day period.

For a non-daily read account, the account may be returned to the applicable Sales Service rate at the end of a billing cycle if the above three conditions are met unless the customer furnishes proof that they did not consume gas on one or more days during such five (5) day period.

RATE

The customers under this rate schedule shall be subject to a Customer Charge and a Distribution Charge. (C)
The Distribution Charge may be subject to an escalation clause.

If a potential customer and the Company cannot agree to terms under this rate schedule, the customer may apply to be classified as a customer under any other rate schedule for which the customer would be eligible.

ELECTIVE BALANCING SERVICES RIDER

Distribution Service under this rate schedule may be subject to the provisions of Rider EBS as set forth in this Tariff.

(C) Indicates Change

RIDER MFC – MERCHANT FUNCTION CHARGE

APPLICABILITY
This Rider shall be applicable to residential customers taking service under Rate Schedules RSS, or CAP (unless an NGS is serving the CAP aggregation) and commercial or industrial customers taking service under Rate Schedule SGSS.

CHARACTER OF RATE

This Rider was established in compliance with the Pennsylvania Public Utility Commission's Revised Final Rulemaking Order dated June 23, 2011 in Docket No. L-2008-2069114 and is addressed in the PA Code Title 52, § 62.223.

The Merchant Function Charge reflects the cost of uncollectibles associated with natural gas costs billed to applicable customers by the Company.

RATE

The MFC is a component of the Price-to-Compare calculation as described in the Definitions section of this tariff.

The uncollectible expense ratios as specified below and determined in the most recent base rate case are used in the calculation of the MFC rate:

Residential uncollectible expense ratio	1.67927%	(I)
Non-residential uncollectible expense ratio	0.46215%	(I)

The current MFC rates may be found in the Rate Summary pages of this Tariff.

CALCULATION OF RATE

The Rider MFC rate is calculated as follows:

MFC = PGCC x the uncollectible expense ratio

where:

PGCC is the current Purchased Gas Commodity Cost as detailed in the Purchased Gas Cost Rider of this tariff.

(D) Indicates Decrease (I) Indicates Increase

RIDER EE - ENERGY EFFICIENCY RIDER (Continued)

ANNUAL RECONCILIATION (C)

Any over or under collection at the end of the plan period shall be recovered or refunded either through a subsequent EE Plan approved by the Commission or through continuation of the EE Rider until full recovery or refunding has occurred.

Within 30 days following the end of the reconciliation period, the Company shall file with the Commission data showing the reconciliation of actual revenues received under this Rider and actual recoverable costs incurred for the preceding twelve months ended December. The resulting over/undercollection (plus interest calculated at 6% annually) will be reflected in the annual rate adjustment to be effective April 1 and will be filed with the Commission at least ten (10) days prior to the effective date.

ANNUAL UPDATES (C)

The EE Rider will be updated annually to be effective January 1 of each year and will be filed with the Commission at least ten (10) days prior to the effective date. The Company reserves the right to make an interim reconciliation filing to adjust the EE Rider and will be filed at least ten (10) days prior to the effective date.

(C) Indicates Change

STATE TAX ADJUSTMENT SURCHARGE

There shall be added to the non-Purchased Gas Cost portion of charges for gas service under all of the Company's rate schedules contained in this Tariff unless otherwise specified below, a surcharge of (0.0000%). (I)

The above surcharge will be recomputed, using the elements prescribed by the Commission:

(a) Whenever any of the tax rates used in calculation of the surcharge are changed;
(b) Whenever the utility makes effective an increase or decrease in base rates, exclusive of Purchased Gas Cost rates and applicable Rider rates;
(c) And by March 31, 1971 and every year thereafter.

The above new recomputation will be submitted to the Commission within ten (10) days after the occurrence of the event or date which occasioned such recomputation. If the recomputed surcharge is less than the one in effect the utility will, and if the recomputed surcharge is more than the one then in effect, the utility may, submit with such recomputation a tariff or supplement to reflect such recomputed surcharge, the effective date of which shall be ten (10) days after filing.

Any charges billed under Rate Schedules CDS, DGDS, EGDS or NCS or charges flexed in accordance with the Flexible Rate Provisions contained in Tariff Rule 20 shall not be subject to the State Tax Adjustment Surcharge.

RULES AND REGULATIONS GOVERNING THE DISTRIBUTION AND SALE OF GAS (Continued)

8. Extensions

8.1 Residential Service Connections (C)

The Company will install the service line from its main to point of delivery, as defined in the Point of Delivery section of this tariff; provided, however;

(a) In the territories formerly served under Tariff Gas--Pa. P.U.C. No. 6 and Tariff Gas--Pa. P.U.C. No. 7, the Company will install at its expense the service line from its main to a convenient point approximately one-hundred fifty (150) feet inside the customer's property line, absent any abnormal underground conditions or excessive permitting requirements. (See the description of Territory section of this tariff to identify territory formerly served under Tariff Gas--Pa. P.U.C. No. 6 and Tariff Gas--Pa. P.U.C. No. 7.)

(b) In rural areas, where service is not available directly from the Company, service may be provided from a transmission or production line. It is the sole discretion of the owner of the transmission or production line to allow service from their facilities to the customer. If connection is allowed, the Company's service connection will consist of a tap on the line and a service valve.

8.2 Capital Expenditure Policy

8.2.1 Residential Distribution Service

The Company, at its discretion, may extend its distribution mains up to a distance of one-hundred fifty (150) feet on any street or highway without cost to an applicant(s), absent any abnormal underground conditions or unusual permitting requirements. When abnormal underground conditions or unusual permitting requirements exist, as determined by the Company, the applicant(s) will be required to pay a refundable cash deposit in an amount determined by the Company.

The applicant(s) will be required to pay a cash deposit to the Company when it is necessary to extend the main line more than one-hundred fifty (150) feet per applicant. The cash deposit will be equal to the difference between the minimum capital investment required to serve the applicant(s)'s gas requirements, excluding the one-hundred fifty (150) foot main allotment per applicant, and the amount of capital that the Company can justify investing in the project, based on the anticipated gas requirements of the applicant(s). The minimum capital investment is the capital expenditure required to serve only the gas requirements requested by the particular applicant(s).

The maximum allowable investment is the amount of capital expenditure which the estimated revenues generated from a proposed project would support and still provide the necessary return to the Company, taking into consideration the estimated additional annual quantities, rate schedule, cost of gas, operating and maintenance expense, interest and taxes.
If the net present value of the project is greater than $1,000 per applicant, the Company may, at its sole discretion, provide a contribution up to $1,000 per applicant, to offset installation costs of gas piping incurred by the applicant(s).

(C) Indicates Change

RATE DGDS - DISTRIBUTED GENERATION DISTRIBUTION SERVICE

APPLICABILITY

Throughout the territory served under this Tariff.

AVAILABILITY

Available, at one location, for the distribution requirements of any commercial or industrial customer using distributed generation equipment such as reciprocating engines, gas turbines, microturbines, and fuel cells used for electrical power generation. Service is available when such customer executes a contract with the Company for a period mutually agreed to between the Company and the customer for distribution service in accordance with all terms and conditions of such contract, provided that the Company's facilities are adequate to provide the requested service.

Service under this rate schedule shall not be available to a single customer who is a Priority 1 Customer, as defined in the Service Limitations section of this Tariff, unless such customer also contracts for firm service under Rate SS-Standby Service at a level necessary to meet the portion of daily and seasonal requirements of the facility not covered by installed operable alternative fuel capability.

CHARACTER OF SERVICE

Service furnished pursuant to this rate schedule shall be subject to termination at the Company's discretion based on its inability to distribute such natural gas. The Company may decline to serve a qualified distribution customer if, in the Company's sole discretion, continuation or initiation of distribution service will jeopardize the supply of gas to the Company's firm customers. If service is terminated under this schedule, the Company will attempt to provide service to a customer under an otherwise applicable rate schedule. In the event of termination, the Company will notify the customer as soon as possible.

A Distributed Generation Distribution Service account may be returned to the applicable Sales Service rate if, for a period of at least five (5) consecutive days in one billing cycle, the Company:

(1) has not received gas supply for the account;
(2) the account's bank balance is insufficient to cover the consumption or the customer did not have access to its bank balance due to the issuance of an OFO and/or OMO; and
(3) the customer consumed gas on one or more days during such five (5) day period.

For a non-daily read account, the account may be returned to the applicable Sales Service rate at the end of a billing cycle if the above three conditions are met unless the customer furnishes proof that they did not consume gas on one or more days during such five (5) day period.

RATE

The customers under this rate schedule shall be subject to a Customer Charge and a Distribution Charge. The Distribution Charge may be subject to an escalation clause. (C)

If a potential customer and the Company cannot agree to terms under this rate schedule, the customer may apply to be classified as a customer under any other rate schedule for which the customer would be eligible.

ELECTIVE BALANCING SERVICES RIDER

Distribution Service under this rate schedule may be subject to the provisions of Rider EBS as set forth in this Tariff.

(C) Indicates Change

RIDER MFC – MERCHANT FUNCTION CHARGE

APPLICABILITY

This Rider shall be applicable to residential customers taking service under Rate Schedules RSS, or CAP (unless an NGS is serving the CAP aggregation) and commercial or industrial customers taking service under Rate Schedule SGSS.

CHARACTER OF RATE

This Rider was established in compliance with the Pennsylvania Public Utility Commission's Revised Final Rulemaking Order dated June 23, 2011 in Docket No. L-2008-2069114 and is addressed in the PA Code Title 52, § 62.223.

The Merchant Function Charge reflects the cost of uncollectibles associated with natural gas costs billed to applicable customers by the Company.

RATE

The MFC is a component of the Price-to-Compare calculation as described in the Definitions section of this tariff.

The uncollectible expense ratios as specified below and determined in the most recent base rate case are used in the calculation of the MFC rate:

Residential uncollectible expense ratio	~~1.44397~~1.67927%	(I)
Non-residential uncollectible expense ratio	~~0.42117~~0.46215%	(I)

The current MFC rates may be found in the Rate Summary pages of this Tariff.

CALCULATION OF RATE

The Rider MFC rate is calculated as follows:

MFC = PGCC x the uncollectible expense ratio

where:

PGCC is the current Purchased Gas Commodity Cost as detailed in the Purchased Gas Cost Rider of this tariff.

(D) Indicates Decrease (I) Indicates Increase

RIDER EE - ENERGY EFFICIENCY RIDER (Continued)

ANNUAL RECONCILIATION (C)

Any over or under collection at the end of the plan period shall be recovered or refunded either through a subsequent EE Plan approved by the Commission or through continuation of the EE Rider until full recovery or refunding has occurred.

Within 30 days following the end of the reconciliation period~~On or before April 1 each year~~, the Company shall file with the Commission data showing the reconciliation of actual revenues received under this Rider and actual recoverable costs incurred for the preceding twelve months ended December. The resulting over/undercollection (plus interest calculated at 6% annually) will be reflected in the annual rate adjustment to be effective April 1 and will be filed with the Commission at least ten (10) days prior to the effective date.

ANNUAL UPDATES (C)

The EE Rider will be updated annually to be effective January 1 of each year and will be filed with the Commission ~~on one day's notice to be~~at least ten (10) days prior to the effective date. ~~effective January 1 of each year.~~ The Company reserves the right to make an interim reconciliation filing to adjust the EE Rider and will be filed at least ten (10) days prior to the effective date.

(C) Indicates Change

STATE TAX ADJUSTMENT SURCHARGE

There shall be added to the non-Purchased Gas Cost portion of charges for gas service under all of the Company's rate schedules contained in this Tariff unless otherwise specified below, a surcharge of (~~0.044~~0.0000%). (I)

The above surcharge will be recomputed, using the elements prescribed by the Commission:

(a) Whenever any of the tax rates used in calculation of the surcharge are changed;
(b) Whenever the utility makes effective an increase or decrease in base rates, exclusive of Purchased Gas Cost rates and applicable Rider rates;
(c) And by March 31, 1971 and every year thereafter.

The above new recomputation will be submitted to the Commission within ten (10) days after the occurrence of the event or date which occasioned such recomputation. If the recomputed surcharge is less than the one in effect the utility will, and if the recomputed surcharge is more than the one then in effect, the utility may, submit with such recomputation a tariff or supplement to reflect such recomputed surcharge, the effective date of which shall be ten (10) days after filing.

Any charges billed under Rate Schedules CDS, DGDS, EGDS or NCS or charges flexed in accordance with the Flexible Rate Provisions contained in Tariff Rule 20 shall not be subject to the State Tax Adjustment Surcharge.

(C) Indicates Change (D) Indicates Decrease (I) Indicates Increase

APPENDIX B

Appendix B

Columbia Gas of Pennsylvania, Inc.
Settlement Revenue Allocation by Class
For the Twelve Months Ending December 31, 2025

	Total	RS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MDS/NSS	FLEX
Settlement Increase	$74,000,000	$48,442,452	$7,287,802	$8,399,452	$5,144,731	$4,725,171	$0	$392

APPENDIX C

Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement

Witness: K. L Johnson

Line No.	Description	Adjusted Bills (1) (Exh. 103, Sch. 2)	Adjusted Volumes (2) DTH (Exh. 103, Sch. 3)	Revenue @ Current Rates (3) $ (Exh. 103, Sch. 1)	Proposed Revenue Increase (4) $	Total Proposed Revenue (5 = 3 + 4) $ (Exh. 103, Sch. 7)	Proposed Increase by Rate Schedule (6) %	Proposed Increase by Rate Class (7) %
1	**Total Revenues**							
2	Residential Sales - RS, CAP	4,445,182	30,308,870.6	$510,032,820	$42,495,095	$552,527,915	8.33%	8.56%
3	Small General Service (≤ 6,440 Therms Annually) - SGSS	283,018	4,173,030.8	$54,784,922	$5,398,044	$60,182,966	9.85%	10.41%
4	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS	33,174	4,167,949.4	$43,880,830	$3,975,717	$47,856,547	9.06%	10.92%
5	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS	962	1,131,330.6	$10,297,401	$788,488	$11,085,889	7.66%	12.41%
6	Large General Sales Service (> 540,000 Therms Annually) - LGSS	36	30,826.3	$322,764	$33,933	$356,697	10.51%	17.25%
7	Negotiated Sales Service - NSS	12	68,000.0	$323,703	$16	$323,719	0.00%	0.04%
8	Residential Distribution Service (Choice) - RDS	532,015	3,782,137.3	$54,127,524	$5,801,479	$59,929,003	10.72%	8.56%
9	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD	85,914	1,242,516.4	$13,257,083	$1,612,348	$14,869,431	12.16%	10.41%
10	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD	15,131	1,696,555.7	$13,715,672	$1,628,106	$15,343,778	11.87%	10.92%
11	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS	9,900	209,051.1	$1,812,411	$258,409	$2,070,820	14.26%	10.41%
12	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS	16,356	2,934,305.7	$19,125,302	$2,774,851	$21,900,153	14.51%	10.92%
13	Small Distribution Service - SDS	4,665	6,299,376.5	$31,058,548	$4,342,475	$35,401,023	13.98%	12.41%
14	Large Distribution Service - LDS	925	11,464,784.9	$27,013,626	$4,680,300	$31,693,926	17.33%	17.25%
15	Main Line Distribution Service Class I - MLDS	49	2,790,000.0	$432,577	$190	$432,767	0.04%	0.04%
16	Main Line Distribution Service Class II - MLDS	61	2,849,000.0	$1,353,532	$596	$1,354,128	0.04%	0.04%
17	Flexible Rate Provisions and Negoitiated Contract Services	144	8,941,200.0	$3,140,571	$447	$3,141,018	0.01%	0.01%
18	Municipal Levelization Charge			$0	$0	$0	0.00%	0.00%
19	Other Gas Department Revenue			$1,427,793	$209,499	$1,637,292	14.67%	14.67%
20	Total Revenues	5,427,544	82,088,935.3	$786,107,079	$ 73,999,993	$ 860,107,072	9.41%	9.41%
21	**Base Rates Revenue Only**							
22	Residential Sales - RS, CAP	4,445,182	30,308,870.6	$350,476,653	$39,015,730	$389,492,383	11.13%	11.26%
23	Small General Service (≤ 6,440 Therms Annually) - SGSS	283,018	4,173,030.8	$37,573,537	$5,381,489	$42,955,026	14.32%	14.34%
24	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS	33,174	4,167,949.4	$26,685,632	$3,963,953	$30,649,585	14.85%	14.99%
25	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS	962	1,131,330.6	$5,641,969	$786,006	$6,427,975	13.93%	13.93%
26	Large General Sales Service (> 540,000 Therms Annually) - LGSS	36	30,826.3	$195,932	$33,847	$229,779	17.27%	17.27%
27	Negotiated Sales Service - NSS	12	68,000.0	$37,160	$0	$37,160	0.00%	0.00%
28	Residential Distribution Service (Choice) - RDS	532,015	3,782,137.3	$43,354,797	$5,326,886	$48,681,683	12.29%	11.26%
29	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD	85,914	1,242,516.4	$11,236,726	$1,607,403	$12,844,129	14.30%	14.34%
30	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD	15,131	1,696,555.7	$10,955,107	$1,623,285	$12,578,392	14.82%	14.99%
31	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS	9,900	209,051.1	$1,733,560	$257,646	$1,991,206	14.86%	14.34%
32	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS	16,356	2,934,305.7	$18,097,100	$2,766,887	$20,863,987	15.29%	14.99%
33	Small Distribution Service - SDS	4,665	6,299,376.5	$31,072,220	$4,328,803	$35,401,023	13.93%	13.93%
34	Large Distribution Service - LDS	925	11,464,784.9	$27,025,517	$4,668,409	$31,693,926	17.27%	17.27%
35	Main Line Distribution Service Class I - MLDS	49	2,790,000.0	$432,767	$0	$432,767	0.00%	0.00%
36	Main Line Distribution Service Class II - MLDS	61	2,849,000.0	$1,354,128	$0	$1,354,128	0.00%	0.00%
37	Flexible Rate Provisions and Negoitiated Contract Services	144	8,941,200.0	$3,140,571	$447	$3,141,018	0.01%	0.01%
38	Total Base Rates Revenues	5,427,544	82,088,935.3	569,013,376	69,760,791	638,774,167	12.26%	12.26%
39	**STAS**							
40	Residential Sales - RS, CAP			($169,239)	$169,239	$0	-100.00%	-100.00%
41	Small General Service (≤ 6,440 Therms Annually) - SGSS			($16,555)	$16,555	$0	-100.00%	-100.00%
42	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			($11,764)	$11,764	$0	-100.00%	-100.00%
43	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			($2,482)	$2,482	$0	-100.00%	-100.00%
44	Large General Sales Service (> 540,000 Therms Annually) - LGSS			($86)	$86	$0	-100.00%	-100.00%
45	Negotiated Sales Service - NSS			($16)	$16	$0	-100.00%	-100.00%
46	Residential Distribution Service (Choice) - RDS			($21,115)	$21,115	$0	-100.00%	-100.00%
47	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD			($4,945)	$4,945	$0	-100.00%	-100.00%
48	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD			($4,821)	$4,821	$0	-100.00%	-100.00%
49	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS			($763)	$763	$0	-100.00%	-100.00%
50	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS			($7,964)	$7,964	$0	-100.00%	-100.00%
51	Small Distribution Service - SDS			($13,672)	$13,672	$0	-100.00%	-100.00%
52	Large Distribution Service - LDS			($11,891)	$11,891	$0	-100.00%	-100.00%
53	Main Line Distribution Service Class I - MLDS			($190)	$190	$0	-100.00%	-100.00%
54	Main Line Distribution Service Class II - MLDS			($596)	$596	$0	-100.00%	-100.00%
55	Flexible Rate Provisions and Negoitiated Contract Services			$0	$0	$0	0.00%	-100.00%
56	Total STAS			($266,099)	$266,099	$0	-100.00%	-100.00%

Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement

Line No.	Description	Adjusted Bills (1) (Exh. 103, Sch. 2)	Adjusted Volumes (2) DTH (Exh. 103, Sch. 3)	Revenue @ Current Rates (3) $ (Exh. 103, Sch. 1)	Proposed Revenue Increase (4) $	Total Proposed Revenue (5 = 3 + 4) $ (Exh. 103, Sch. 7)	Proposed Increase by Rate Schedule (6) %	Proposed Increase by Rate Class (7) %
1	**Rider CC**							
2	Residential Sales - RS, CAP			$27,607	$0	$27,607	0.00%	0.00%
3	Small General Service (≤ 6,440 Therms Annually) - SGSS			$4,173	$0	$4,173	0.00%	0.00%
4	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$4,168	$0	$4,168	0.00%	0.00%
5	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			$0	$0	$0	0.00%	0.00%
6	Large General Sales Service (> 540,000 Therms Annually) - LGSS			$0	$0	$0	0.00%	0.00%
7	Negotiated Sales Service - NSS			$0	$0	$0	0.00%	0.00%
8	Residential Distribution Service (Choice) - RDS			$3,782	$0	$3,782	0.00%	0.00%
9	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD			$1,243	$0	$1,243	0.00%	0.00%
10	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD			$1,697	$0	$1,697	0.00%	0.00%
11	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS			$209	$0	$209	0.00%	0.00%
12	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS			$2,934	$0	$2,934	0.00%	0.00%
13	Small Distribution Service - SDS			$0	$0	$0	0.00%	0.00%
14	Large Distribution Service - LDS			$0	$0	$0	0.00%	0.00%
15	Main Line Distribution Service Class I - MLDS			$0	$0	$0	0.00%	0.00%
16	Main Line Distribution Service Class II - MLDS			$0	$0	$0	0.00%	0.00%
17	Flexible Rate Provisions and Negoitiated Contract Services			$0	$0	$0	0.00%	0.00%
18	Total Rider CC			$45,813	$0	$45,813	0.00%	0.00%
19	**Rider EE - Energy Efficiency Rider**							
20	Residential Sales - RS, CAP			$1,098,774	$0	$1,098,774	0.00%	0.00%
21	Small General Service (≤ 6,440 Therms Annually) - SGSS			$0	$0	$0	0.00%	0.00%
22	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$0	$0	$0	0.00%	0.00%
23	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			$0	$0	$0	0.00%	0.00%
24	Large General Sales Service (> 540,000 Therms Annually) - LGSS			$0	$0	$0	0.00%	0.00%
25	Negotiated Sales Service - NSS			$0	$0	$0	0.00%	0.00%
26	Residential Distribution Service (Choice) - RDS			$150,529	$0	$150,529	0.00%	0.00%
27	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD			$0	$0	$0	0.00%	0.00%
28	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD			$0	$0	$0	0.00%	0.00%
29	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS			$0	$0	$0	0.00%	0.00%
30	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS			$0	$0	$0	0.00%	0.00%
31	Small Distribution Service - SDS			$0	$0	$0	0.00%	0.00%
32	Large Distribution Service - LDS			$0	$0	$0	0.00%	0.00%
33	Main Line Distribution Service Class I - MLDS			$0	$0	$0	0.00%	0.00%
34	Main Line Distribution Service Class II - MLDS			$0	$0	$0	0.00%	0.00%
35	Flexible Rate Provisions and Negoitiated Contract Services			$0	$0	$0	0.00%	0.00%
36	Total Rider EE			$1,249,303	$0	$1,249,303	0.00%	0.00%
37	**Gas Procurement Charge**							
38	Residential Sales - RS, CAP			$342,491	$0	$342,491	0.00%	0.00%
39	Small General Service (≤ 6,440 Therms Annually) - SGSS			$47,155	$0	$47,155	0.00%	0.00%
40	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$47,098	$0	$47,098	0.00%	0.00%
41	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			$12,784	$0	$12,784	0.00%	0.00%
42	Large General Sales Service (> 540,000 Therms Annually) - LGSS			$348	$0	$348	0.00%	0.00%
43	Negotiated Sales Service - NSS			$0	$0	$0	0.00%	0.00%
44	Residential Distribution Service (Choice) - RDS			$0	$0	$0	0.00%	0.00%
45	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD			$0	$0	$0	0.00%	0.00%
46	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD			$0	$0	$0	0.00%	0.00%
47	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS			$0	$0	$0	0.00%	0.00%
48	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS			$0	$0	$0	0.00%	0.00%
49	Small Distribution Service - SDS			$0	$0	$0	0.00%	0.00%
50	Large Distribution Service - LDS			$0	$0	$0	0.00%	0.00%
51	Main Line Distribution Service Class I - MLDS			$0	$0	$0	0.00%	0.00%
52	Main Line Distribution Service Class II - MLDS			$0	$0	$0	0.00%	0.00%
53	Flexible Rate Provisions and Negoitiated Contract Services			$0	$0	$0		
54	Total Gas Procurement Charge			$449,876	$0	$449,876	0.00%	0.00%

Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement

Line No.	Description	Adjusted Bills (1) (Exh. 103, Sch. 2)	Adjusted Volumes (2) DTH (Exh. 103, Sch. 3)	Revenue @ Current Rates (3) $ (Exh. 103, Sch. 1)	Proposed Revenue Increase (4) $	Total Proposed Revenue (5 = 3 + 4) $ (Exh. 103, Sch. 7)	Proposed Increase by Rate Schedule (6) %	Proposed Increase by Rate Class (7) %
1	**Universal Service Plan Rider**							
2	Residential Sales - RS			$32,689,913	$3,310,126	$36,000,039	10.13%	10.13%
3	Small General Service (≤ 6,440 Therms Annually) - SGSS			$0	$0	$0	0.00%	0.00%
4	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$0	$0	$0	0.00%	0.00%
5	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			$0	$0	$0	0.00%	0.00%
6	Large General Sales Service (> 540,000 Therms Annually) - LGSS			$0	$0	$0	0.00%	0.00%
7	Negotiated Sales Service - NSS			$0	$0	$0	0.00%	0.00%
8	Residential Distribution Service (Choice) - RDS			$4,478,429	$453,478	$4,931,907	10.13%	10.13%
9	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD			$0	$0	$0	0.00%	0.00%
10	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD			$0	$0	$0	0.00%	0.00%
11	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS			$0	$0	$0	0.00%	0.00%
12	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS			$0	$0	$0	0.00%	0.00%
13	Small Distribution Service - SDS			$0	$0	$0	0.00%	0.00%
14	Large Distribution Service - LDS			$0	$0	$0	0.00%	0.00%
15	Main Line Distribution Service Class I - MLDS			$0	$0	$0	0.00%	0.00%
16	Main Line Distribution Service Class II - MLDS			$0	$0	$0	0.00%	0.00%
17	Flexible Rate Provisions and Negoitiated Contract Services			$0	$0	$0		
18	Total Universal Service Charge			$37,168,342	$3,763,604	$40,931,946	10.13%	10.13%
19	**Merchant Function Charge**							
20	Residential Sales - RS, CAP			$1,121,429	$0	$1,121,429	0.00%	0.00%
21	Small General Service (≤ 6,440 Therms Annually) - SGSS			$42,565	$0	$42,565	0.00%	0.00%
22	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$42,513	$0	$42,513	0.00%	0.00%
23	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			$0	$0	$0	0.00%	0.00%
24	Large General Sales Service (> 540,000 Therms Annually) - LGSS			$0	$0	$0	0.00%	0.00%
25	Negotiated Sales Service - NSS			$0	$0	$0	0.00%	0.00%
26	Residential Distribution Service (Choice) - RDS			$0	$0	$0	0.00%	0.00%
27	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD			$0	$0	$0	0.00%	0.00%
28	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD			$0	$0	$0	0.00%	0.00%
29	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS			$0	$0	$0	0.00%	0.00%
30	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS			$0	$0	$0	0.00%	0.00%
31	Small Distribution Service - SDS			$0	$0	$0	0.00%	0.00%
32	Large Distribution Service - LDS			$0	$0	$0	0.00%	0.00%
33	Main Line Distribution Service Class I - MLDS			$0	$0	$0	0.00%	0.00%
34	Main Line Distribution Service Class II - MLDS			$0	$0	$0	0.00%	0.00%
35	Flexible Rate Provisions and Negoitiated Contract Services			$0	$0	$0	0.00%	0.00%
36	Total Merchant Function Charge			$1,206,507	$0	$1,206,507	0.00%	0.00%
37	**Gas Cost**							
38	Residential Sales - RS, CAP			$124,445,192	$0	$124,445,192	0.00%	0.00%
39	Small General Service (≤ 6,440 Therms Annually) - SGSS			$17,134,047	$0	$17,134,047	0.00%	0.00%
40	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$17,113,183	$0	$17,113,183	0.00%	0.00%
41	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			$4,645,130	$0	$4,645,130	0.00%	0.00%
42	Large General Sales Service (> 540,000 Therms Annually) - LGSS			$126,570	$0	$126,570	0.00%	0.00%
43	Negotiated Sales Service - NSS			$286,559	$0	$286,559	0.00%	0.00%
44	Residential Distribution Service (Choice) - RDS			$6,161,102	$0	$6,161,102	0.00%	0.00%
45	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD			$2,024,059	$0	$2,024,059	0.00%	0.00%
46	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD			$2,763,689	$0	$2,763,689	0.00%	0.00%
47	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS			$79,405	$0	$79,405	0.00%	0.00%
48	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS			$1,033,232	$0	$1,033,232	0.00%	0.00%
49	Small Distribution Service - SDS			$0	$0	$0	0.00%	0.00%
50	Large Distribution Service - LDS			$0	$0	$0	0.00%	0.00%
51	Main Line Distribution Service Class I - MLDS			$0	$0	$0	0.00%	0.00%
52	Main Line Distribution Service Class II - MLDS			$0	$0	$0	0.00%	0.00%
53	Flexible Rate Provisions and Negoitiated Contract Services			$0	$0	$0	0.00%	0.00%
54	Total Gas Cost			$175,812,168	$0	$175,812,168	0.00%	0.00%

Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement

Line No.	Description	Total (1)	RS/RDS/RC2 (2)	SGSS1/SCD1/SGDS1 (3)	SGSS2/SCD2/SGDS2 (3)	SDS/LGS (4)	LDS/LGS (5)	MDS/NSS (6)	Flex/NCS (7)
1	**Determination of Revenue Distribution**								
2	Rate Base (Exhibit 111, Schedule 2, Page 2, Line 12)	$3,489,087,566	$2,073,236,314	$300,383,729	$358,941,049	$230,044,493	$296,525,015	$523,759	$229,433,208
3									
4	Unitized Return @ Current Rates (Exhibit 111, Schedule 2, Page 2, Line 14)	1.00000	1.21403	1.09168	1.08091	1.13573	0.34323	40.02251	(0.55775)
5	**Proposed Unitized Return**	**1.00000**	**1.20098**	**1.07989**	**1.04825**	**1.09380**	**0.41181**	**28.16734**	**(0.39259)**
6	**Change in Unitized Return**	**0.00000**	**(0.01305)**	**(0.01179)**	**(0.03266)**	**(0.04193)**	**0.06858**	**(11.85517)**	**0.16516**
7	Rate of Return Requested	8.710%	10.461%	9.406%	9.130%	9.527%	3.587%	245.338%	-3.419%
8	Net Operating Income @ Requested Return (Line 2 x Line 7)	$303,899,527	$216,881,251	$28,254,094	$32,771,318	$21,916,339	$10,635,863	$1,284,983	($7,844,321)
9	Net Operating Income @ Current Rates (Exhibit 111, Sch. 2, Page 2, Line 11)	$213,868,484	$154,290,367	$20,100,832	$23,783,054	$16,014,922	$6,239,603	$1,284,980	($7,845,274)
10	Income Deficiency (Line 8 - Line 9)	$90,031,043	$62,590,884	$8,153,262	$8,988,264	$5,901,417	$4,396,260	$3	$953
11	Gross Converstion Factor	1.37884083	1.37884083	1.37884083	1.37884083	1.37884083	1.37884083	1.37884083	1.37884083
12	**Revenue Required Increase (Exhibit 102 Sch. 3 Page 3)**	**124,138,478**	**86,302,867**	**11,242,051**	**12,393,385**	**8,137,115**	**6,061,742**	**4**	**1,314**
13	Revenue Requirement Change Due to Settlement	(50,138,478)	(37,860,415)	(3,954,249)	(3,993,933)	(2,992,384)	(1,336,571)	(4)	(922)
14	**Revenue Required Increase per Settlement**	**74,000,000**	**48,442,452**	**7,287,802**	**8,399,452**	**5,144,731**	**4,725,171**	**0**	**392**
15	**Percent Distribution to Rate Classes**	**100.00%**	**65.46%**	**9.85%**	**11.35%**	**6.95%**	**6.39%**	**0.00%**	**0.00%**
16	Less: #NAME?	266,099	191,156	22,263	24,549	16,154	11,977	0	0
17	Less: Proposed Change Other Gas Department Revenue (Page 1 Line 20)	209,499	145,648	18,972	20,915	13,732	10,230	0	2
18	Less: Proposed Change in Rider CC (Page 2 Line 3 through Line 37)	0	0	0	0	0	0	0	0
19	Less: Proposed Change in Gas Procurement Revenue (Page 2 Line 43 through Line)	0	0	0	0	0	0	0	0
20	**Proposed Increase to Base Revenue**	**$73,524,402**	**$48,105,648**	**$7,246,567**	**$8,353,988**	**$5,114,845**	**$4,702,964**	**$0**	**$390**
21	**Percent Distribution to Rate Classes**	**100.00%**	**65.42%**	**9.86%**	**11.36%**	**6.96%**	**6.40%**	**0.00%**	**0.00%**
22	**Current Base Revenue**	**$568,744,881**	**$393,641,096**	**$50,521,560**	**$55,713,290**	**$36,698,035**	**$27,207,076**	**$1,823,253**	**$3,140,571**
23	**Current Percent Distribution of Rate Classes**	**100.00%**	**69.21%**	**8.88%**	**9.80%**	**6.45%**	**4.78%**	**0.32%**	**0.55%**
24	**Proposed Base Revenue**	**$642,269,283**	**$441,746,744**	**$57,768,127**	**$64,067,278**	**$41,812,880**	**$31,910,040**	**$1,823,253**	**$3,140,961**
25	**Proposed Percent Distribution of Rate Classes**	**100.00%**	**68.78%**	**8.99%**	**9.98%**	**6.51%**	**4.97%**	**0.28%**	**0.49%**

Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement

Line No.			Bills	Dth	Proposed Rate $	Proposed Revenue $	Current Revenue $	Percent of Current Revenue %	Current Rate $	Proposed Inc. (Dec.) $
1		**Residential Rate Design (RS, RDS, RC2)**								
2		Total Revenue @ Current Rates				$564,160,344				
3	Less:	STAS				(190,354)				
4	Less:	Gas Cost Revenue				130,606,294				
5	Less:	Gas Procurement Charge				342,491				
6	Less:	Rider CC				31,389				
7	Less:	Rider EE				1,249,303				
8	Less:	Merchant Function Charge				1,121,429				
9	Less:	Rider USP				37,168,342				
10	Plus:	Proposed Increase to Base Rates				48,105,648				
11		Proposed Base Revenue				$441,937,098				
12	Less:	Customer Charge Revenue (Exhibit 103, Sch. 1)	4,977,197		**17.25**	85,856,648	83,368,050	21.17%	16.75	2,488,598
13		Net Volumetric Gas Revenue				$356,080,450				
14		All Gas Consumed (Exhibit 103, Sch. 1)		34,091,007.9	**10.4450**	$356,080,578	$310,463,400	78.83%	9.1069	45,617,178
15		Total Base Revenue Charge						100.00%		**$48,105,776**
16		**Rider USP - Universal Service Plan**								
17		Universal Service Plan Rider @ Current Rate				37,168,342				
18	Plus:	Redistribution of CAP shortfall resulting from proposed rates				3,763,160				
19		Expected Change in Universal Service Plan Rider Rate		31,389,529.5	1.3040	$40,931,502			1.1841	

Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement

Line No.			Bills	Dth	Proposed Rate $	Proposed Revenue $	Current Revenue $	Percent of Current Revenue %	Current Rate $	Proposed Inc. (Dec.) $
1		**Small General Service Rate Design ≤ 6,440 Thms Annually (SGSS1, SCD1, SGDS1)**								
2		Total Revenue @ Current Rates				$69,854,416				
3	Less:	STAS				(22,263)				
4	Less:	Gas Cost Revenue				19,237,511				
5	Less:	Gas Procurement Charge				47,155				
6	Less:	Rider CC				5,625				
7	Less:	Merchant Function Charge				42,565				
8	Less:	Rider USP				0				
9	Plus:	Proposed Increase to Base Rates				7,246,567				
10		Proposed Base Revenue				$57,790,390				
11	Less:	Customer Charge Revenue (Exhibit 103, Sch. 1) ≤ 6,440 Thms	378,832		**33.00**	12,501,456	11,334,654	22.43%	29.92	1,166,802
12		Net Volumetric Gas Revenue				$45,288,934				
13		All Gas Consumed Rate		5,624,598.3	8.0519	45,288,703				
14		SGSS1,SCD1 @ uniform rate		5,415,547.2	8.0519	43,605,444				
15		SGDS1 @ uniform rate		209,051.1	8.0519	1,683,259				
16		Intra-Class Adjustment - SGDS1 to SGSS1/SCD1 (Exhibit KLJ-4)				18,748				
17		Less Than 6,440 Therms Annually - SGSS1, SCD1		5,415,547.2	**8.0554**	43,624,192	37,771,817	74.73%	6.9747	5,852,375
18		Less Than 6,440 Therms Annually - SGDS1		209,051.1	**7.9622**	1,664,511	1,437,352	2.84%	6.8756	227,159
						57,790,159	$50,543,823	100.00%		
19		Total Base Revenue Charge								**$7,246,336**

Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement

Line No.			Bills	Dth	Proposed Rate $	Proposed Revenue $	Current Revenue $	Percent of Current Revenue %	Current Rate $	Proposed Inc. (Dec.) $
1		**Small General Service Rate Design > 6,440 to ≤ 64,400 Thms Annually (SGSS2, SCD2, SGDS2)**								
2		Total Revenue @ Current Rates				$76,721,804				
3	Less:	STAS				(24,549)				
4	Less:	Gas Cost Revenue				20,910,104				
5	Less:	Gas Procurement Charge				47,098				
6	Less:	Rider CC				8,799				
7	Less:	Merchant Function Charge				42,513				
8	Less:	Rider USP				0				
9	Plus:	Proposed Increase to Base Rates				8,353,988				
10		Proposed Base Revenue				$64,091,827				
11	Less:	Customer Charge Revenue (Exhibit 103, Sch. 1) > 6,440 to ≤ 64,440 Thms	64,661		**63.00**	4,073,643	3,685,677	6.61%	57.00	387,966
12		Net Volumetric Gas Revenue				$60,018,184				
13		All Gas Consumed Rate		8,798,810.8	6.8212	60,018,448				
14		SGSS2,SCD2 @ uniform rate		5,864,505.1	6.8212	40,002,962				
15		SGDS2 @ uniform rate		2,934,305.7	6.8212	20,015,486				
16		Intra-Class Adjustment - SGDS2 to SGSS2/SCD2 (Exhibit KLJ-4)				182,002	200,750			
17		6,440 - 64,400 Therms Annually - SGSS2, SCD2		5,864,505.1	**6.8522**	40,184,964	34,887,354	62.59%	5.9489	5,297,610
18		6,440 - 64,400 Therms Annually - SGDS2		2,934,305.7	**6.7592**	19,833,484	17,164,808	30.80%	5.8497	2,668,676
						$60,018,448	$52,052,162	100.00%		
19		Total Base Revenue Charge								**8,354,252**

Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement

Line No.			Bills	Dth	Proposed Rate $	Proposed Revenue $	Current Revenue $	Percent of Current Revenue %	Current Rate $	Proposed Inc. (Dec.) $
1		**Small Distribution Service Rate Design (SDS/LGSS)**								
2		Total Revenue @ Current Rates				$41,355,949				
3	Less:	STAS				(16,154)				
4	Less:	Gas Cost Revenue				4,645,130				
5	Less:	Gas Procurement Charge				12,784				
6	Plus:	Proposed Increase to Base Rates				5,114,845				
7		Proposed Base Revenue				$41,829,034				
8	Less:	Customer Charge Revenue (Exhibit 103, Sch. 1) > 64,400 to ≤ 110,000 Thms	2,596		**304.32**	790,015	693,418		267.11	96,597
9	Less:	Customer Charge Revenue (Exhibit 103, Sch. 1) > 110,000 to ≤ 540,000 Thms	3,031		**1,380.38**	4,183,932	3,672,330		1,211.59	511,602
10		Net Volumetric Gas Revenue				$36,855,087				
11		> 64,400 to ≤ 110,00 Therms Annually (Exhibit 103, Sch. 1)		2,061,353.3	**5.2045**	10,728,330	9,416,468	29.11%	4.5681	1,311,862
12		> 110,000 to <= 540,000 Therms Annually (Exhibit 103, Sch. 1)		5,369,353.8	**4.8659**	26,126,757	22,931,973	70.89%	4.2709	3,194,784
						36,855,087	$32,348,441	100.00%		4,506,646
13		Total Base Revenue Charge								**5,114,845**
14		**Large Distribution Service Rate Design (LDS/LGSS)**								
15		Total Revenue @ Current Rates				$27,336,390				
16	Less:	STAS				(11,977)				
17	Less:	Gas Cost Revenue				126,570				
18	Less:	Gas Procurement Charge				348				
19	Plus:	Proposed Increase to Base Rates				4,702,964				
20		Proposed Base Revenue				$31,924,413				
21	Less:	Customer Charge Revenue (Exhibit 103, Sch. 1)								
22		> 540,000 to ≤ 1,074,000 Thms	529		**3,502.84**	1,853,002	1,580,028		2,986.82	272,974
23		> 1,074,000 to ≤ 3,400,000 Therms Annually	372		**5,448.36**	2,026,790	1,728,212		4,645.73	298,578
24		> 3,400,000 to ≤ 7,500,000 Therms Annually	48		**10,506.98**	504,335	430,039		8,959.14	74,296
25		> 7,500,000 Therms Annually	12		**15,565.61**	186,787	159,271		13,272.55	27,516
26		Net Volumetric Gas Revenue				$27,353,499				
27		Usage Charge (Exhibit 103, Sch. 1)								
28		> 540,000 to ≤ 1,074,000 Thms		3,107,499.2	**2.7481**	8,539,858	7,281,803	31.22%	2.3433	1,258,055
29		> 1,074,000 to ≤ 3,400,000 Therms Annually		5,641,112.0	**2.4375**	13,750,754	11,725,052	50.27%	2.0785	2,025,702
30		> 3,400,000 to ≤ 7,500,000 Therms Annually		1,679,000.0	**2.1874**	3,672,720	3,131,671	13.43%	1.8652	541,049
31		> 7,500,000 Therms Annually		1,068,000.0	**1.3017**	1,390,166	1,185,373	5.08%	1.1099	204,793
						$27,353,498	$23,323,899	100.00%		$4,029,599
32		Total Base Revenue Charge								**$4,702,963**

Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement

Line No.			Bills	Dth	Proposed Rate $	Proposed Revenue $	Current Revenue $	Percent of Current Revenue %	Current Rate $	Proposed Inc. (Dec.) $
1		**Main Line Service Rate Design - Class I (NSS and MLDS-I) and MDS Class II**								
2		Total Revenue @ Current Rates				$2,109,812				
3	Less:	STAS				(802)				
4	Less:	Gas Cost Revenue				286,559				
5	Plus:	Proposed Increase to Base Rates				0				
6		Proposed Base Revenue				$1,824,055				
7	Less:	MDS I Customer Charge Revenue (Exhibit 103, Sch. 1)								
8		> 274,000 to ≤ 540,000 Thms	12		**469.34**	5,632	5,632		469.34	0
9		> 540,000 to ≤ 1,074,000 Therms Annually	12		**1,149.00**	13,788	13,788		1,149.00	0
10		> 1,074,000 to ≤ 3,400,000 Therms Annually	12		**2,050.00**	24,600	24,600		2,050.00	0
11		> 3,400,000 to ≤ 7,500,000 Therms Annually	13		**4,096.00**	53,248	53,248		4,096.00	0
12		> 7,500,000 Therms Annually	12		**7,322.00**	87,864	87,864		7,322.00	0
13	Less:	MDS II Customer Charge Revenue (Exhibit 103, Sch. 1)								
14		> 2,146,000 to ≤ 3,400,000 Therms Annually	0		**2,050.00**	0	0		2,050.00	-
15		> 3,400,000 to ≤ 7,500,000 Therms Annually	61		**4,096.00**	249,856	249,856		4,096.00	-
16		> 7,500,000 Therms Annually	0		**7,322.00**	0	0		7,322.00	-
17		Net Volumetric Gas Revenue				$1,389,067				
18		MDS I Usage Charge (Exhibit 103, Sch. 1)		2,790,000.0	**0.0937**	261,423	261,423	18.82%	0.0937	-
19		NSI Usage Charge (exhibit 103, Sch. 1)		68,000.0	**0.3437**	23,372	23,372	1.68%	0.3437	-
20		MDS II Usage Charge (Exhibit 103, Sch. 1)								
21		> 2,146,000 to ≤ 3,400,000 Therms Annually		0.0	**0.0000**	0	0	0.00%	0.4481	0
22		> 3,400,000 to <= 7,500,000 Therms Annually		2,849,000.0	**0.3876**	1,104,272	1,104,272	79.50%	0.3876	0
23		> 7,500,000 Therms Annually		0.0	**0.3355**	0	0	0.00%	0.3355	0
24								100.00%		
25		Total Base Revenue Charge								**-**
26		**Flexible Rate and Negotiated Contract Services**								
27		Total Revenue @ Current Rates				3,140,571				
28	Less:	STAS				0				
29	Less:	Gas Cost Revenue				0				
30	Plus:	Proposed Increase to Base Rates				$390				
31		Proposed Base Revenue				$3,140,961				
32	Less:	Negotiated Contract Service Customer Charge				$1,280,632				
33	Less:	Commodity All Gas Consumed				$1,856,734				
34	Less:	Flex Customer Charge Revenue (Exhibit 103, Sch. 1)								
35		SGDS-1 Less Than 6,440 Therms Annually	0		**33.00**	0	0		29.92	0
36		SGDS-2 >6,440 to ≤ 64,400 Therms Annually	0		**63.00**	0	0		57.00	0
37		SDS > 64,400 to ≤ 110,000 Therms Annually	12		**304.32**	3,652	3,205		267.11	447
38		SDS > 110,000 to ≤ 540,000 Therms Annually	0		**1,380.38**	0	0		1,211.59	0
39		LDS > 540,000 to ≤ 1,074,000 Therms Annually	0		**3,502.84**	0	0		2,986.82	0
40		LDS >1,074,000 to ≤ 3,400,000 Therms Annually	0		**5,448.36**	0	0		4,645.73	0
41		LDS > 3,400,000 to ≤ 7,500,000 Therms Annually	0		**10,506.98**	0	0		8,959.14	0
42		LDS > 7,500,000 Therms Annually	0		**15,565.61**	0	0		13,272.55	0
43		MDS-I > 274,000 to ≤ 540,000 Therms Annually	0		**469.34**	0	0		469.34	0
44		MDS-I > 540,000 to ≤ 1,074,000 Therms Annually	0		**1,149.00**	0	0		1,149.00	0
45		MDS-I > 1,074,000 to ≤ 3,400,000 Therms Annually	0		**2,050.00**	0	0		2,050.00	0
46		MDS-I > 3,400,000 to ≤ 7,500,000 Therms Annually	0		**4,096.00**	0	0		4,096.00	0
47		MDS-I > 7,500,000 Therms Annually	0		**7,322.00**	0	0		7,322.00	0
48		MDS-II > 2,146,000 to ≤ 3,400,000 Therms Annually	0		**2,050.00**	0	0		2,050.00	0
49		MDS-II > 3,400,000 to ≤ 7,500,000 Therms Annually	0		**4,096.00**	0	0		4,096.00	0
50		MDS-II > 7,500,000 Therms Annually	0		**7,322.00**	0	0		7,322.00	0
		Total Flex Customer Charge				3,652				
51		Total Base Revenue Charge								**447**

APPENDIX D

I. PROPOSED CONCLUSIONS OF LAW

1. The Commission has jurisdiction over the subject matter and the parties to this proceeding. 66 Pa. C.S. §§ 1301, 1308(d).

2. Under Section 1301 of the Public Utility Code, a public utility's rates must be just and reasonable. 66 Pa. C.S. § 1301.

3. The Commission possesses a great deal of flexibility in its ratemaking function. *See Popowsky v. Pa. Pub. Util. Comm'n*, 542 Pa. 99, 108, 665 A.2d 808, 812 (Pa. 1995). "In determining just and reasonable rates, the [Commission] has discretion to determine the proper balance between the interests of ratepayers and utilities." *Id.*

4. The term "just and reasonable" is not intended to confine the ambit of regulatory discretion to an absolute or mathematical formulae; rather, the Commission is granted the power to balance the prices charged to utility customers and returns on capital to utility investors. *Pa. Pub. Util. Comm'n v. Pennsylvania Gas and Water Co.*, 494 Pa. 326, 337, 424 A.2d 1213, 1219 (Pa. 1980), *cert. denied*, 454 U.S. 824, 102 S. Ct. 112, 70 L. Ed. 2d 97 (1981).

5. Commission policy promotes settlements. 52 Pa. Code § 5.231. Settlements lessen the time and expense the parties must expend litigating a case and at the same time conserve administrative resources.

6. Settlement results are often preferable to those achieved at the conclusion of a fully litigated proceeding. 52 Pa. Code § 69.401.

7. The Commission encourages black box settlements. *Pa. P.U.C. v. Aqua Pennsylvania, Inc.*, Docket No. R-2011-2267958, Order entered June 7, 2012, pp. 26-27; *Pa. P.U.C. v. Peoples TWP LLC*, Docket No. R-2013-2355886, Order entered December 19, 2013, p. 27 ("*Peoples TWP LLC*"); Statement of Chairman Robert F. Powelson, *Implementation of Act 11 of 2012*, Docket No. M-2012-2293611, Public Meeting, August 2, 2012.

8. In order to accept a settlement, the Commission must determine that the proposed terms and conditions are in the public interest. *Pa. Pub. Util. Comm'n, et al. v. UGI Utilities, Inc. – Gas Division*, Docket Nos. R-2015-2518438 et al. (Order entered Oct. 14, 2016); *Pa. Pub. Util. Comm'n v. Philadelphia Gas Works*, Docket No. M-00031768 (Order entered Jan. 7, 2004).

9. The Petitioners have the burden to prove that the Settlement is in the public interest. *Pa. Pub. Util. Comm'n, et al. v. Pike County Light & Power (Electric)*, Docket Nos. R-2013-2397237, C-2014-2405317, et al. (Order entered Sept. 11, 2014).

10. The decision of the Commission must be supported by substantial evidence. 2 Pa. C.S. § 704.

11. "Substantial evidence" is such relevant evidence that a reasonable mind might accept as adequate to support a conclusion. More is required than a mere trace of evidence or a suspicion of the existence of a fact sought to be established. *Norfolk & Western Ry. Co. v. Pa. P.U.C.*, 489 Pa. 109, 413 A.2d 1037 (1980); *Erie Resistor Corp. v. Unemployment Comp. Bd. of Review*, 194 Pa. Superior Ct. 278, 166 A.2d 96 (1961); *Murphy v. Comm., Dept. of Public Welfare, White Haven Center*, 85 Pa. Commonwealth Ct. 23, 480 A.2d 382 (1984).

12. The rates and terms of service set forth in the Settlement are supported by substantial evidence and are in the public interest, as set forth in the Joint Petitioners' Statements in Support. Therefore, consistent with the terms and conditions set forth in the Settlement, Columbia Gas of Pennsylvania, Inc.'s ("Columbia") rate increase of $74.0 Million should be granted.

II. PROPOSED ORDERING PARAGRAPHS

1. That the Pennsylvania Public Utility Commission approve the Joint Petition for Settlement, including all the terms and modifications thereof, without modification.

2. That the Pennsylvania Public Utility Commission approve the proposals set forth in Columbia's above-captioned distribution base rate increase filing subject to the terms and conditions of the Joint Petition for Settlement.

3. That the Commission's investigation at Commission Docket R-2024-3046519, and the Complaints of the OCA (C-2024-3047675), OSBA (C-2024-3047905), Ronald T. Bernick (C-2024-3048339), Linda Allison (C-2024-3048588), Philip Bloch (C-2024-3048478, PSU (C-2024-3048624), and Daniel E. Skvarla (C-2024-3049677) be marked closed. The Formal Complaints filed by OCA, OSBA, and the individual customer complainants are marked as satisfied and closed.

4. That the Commission issue an Order ruling on the issue reserved for litigation.