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September 2, 2016

VIA ELECTRONIC FILING

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

Re: Pennsylvania Public Utility Commission, et al. v. Columbia Gas of Pennsylvania, Inc.
Docket Nos. R-2016-2529660, etc.

Dear Secretary Chiavetta:

Attached please find the Joint Petition for Settlement of the above-referenced proceeding. Copies will be provided as indicated on the Certificate of Service.

Respectfully submitted,

Michael W. Hassell

MWH/skr
Enclosure

cc: Certificate of Service
Honorable Katrina L. Dunderdale
Debra Backer (*via e-mail*)
Jeffrey McCracken (*via e-mail*)
Marc Hoffer (*via e-mail*)
Marie Intrieri (*via e-mail*)

CERTIFICATE OF SERVICE
(Docket No. R-2016-2529660)

I hereby certify that a true and correct copy of the foregoing has been served upon the following persons, in the manner indicated, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

VIA E-MAIL AND FIRST CLASS MAIL

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Bradford, PA 16701

Date: September 2, 2016

Lindsay A. Berkstresser

Lindsay A. Berkstresser

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2016-2529660
Office of Consumer Advocate	:	C-2016-2535301
Office of Small Business Advocate	:	C-2016-2538051
Columbia Industrial Intervenors	:	C-2016-2541753
Pennsylvania State University	:	C-2016-2541623
Ralph Miller	:	C-2016-2538611
Michael Pikus	:	C-2016-2538843
Richard Collins	:	C-2016-2547479
James Testrake	:	C-2016-2555931
	:	
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

JOINT PETITION FOR SETTLEMENT

TO ADMINISTRATIVE LAW JUDGE KATRINA L. DUNDERDALE:

I. INTRODUCTION

The Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), Columbia Industrial Intervenors ("CII"),[1] Dominion Retail, Inc. ("Dominion"), Shipley Energy Company ("Shipley"), Interstate Gas Supply, Inc. ("IGS") and AMERIGreen Energy ("AMERIGreen"),[2] Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), Community Action Association of Pennsylvania ("CAAP"), The Pennsylvania State University ("PSU"), Direct Energy Business, LLC, Direct Energy Services, LLC, and

---

[1] CII's members for purposes of this proceeding are Glen-Gery Corporation and Knouse Foods Cooperative, Inc.

[2] For purposes of this Settlement, Dominion, Shipley, IGS and AMERIGreen are referred to collectively as the NGS Parties.

Direct Energy Business Marketing, LLC (collectively, "Direct Energy") 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 hereby respectfully request that Administrative Law Judge Katrina L. Dunderdale ("ALJ Dunderdale" or the "ALJ") and the Commission expeditiously approve the Settlement as set forth below. The Settlement has been agreed to or is not opposed by all active parties in this proceeding.[3]

As fully set forth and explained below, the Joint Petitioners have agreed to a settlement of all issues in the above-captioned general base rate proceeding (the "2016 Base Rate Filing"). Among other provisions, the Settlement provides for increases in rates designed to produce $35 million in additional base rate revenue based upon the pro forma level of operations for the twelve months ended December 31, 2017. 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 421,000 residential, commercial, and industrial customers in portions of 26 counties of Pennsylvania.

[3] Four individual Columbia customers filed Formal Complaints against the Company's proposed rate increase. However, the customers did not attend the Prehearing Conference, did not file testimony, and did not otherwise actively participate in this matter. As indicated on the Certificate of Service, Columbia is serving a copy of the Settlement on the inactive customer complainants.

2. On March 18, 2016, Columbia filed with the Commission Supplement No. 241 to its Tariff Gas – Pa. P.U.C. No. 9 ("Supplement No. 241" or "base rate filing"). Supplement No. 241, issued March 18, 2016 and to be effective May 17, 2016, proposed an increase in revenues of approximately $55.3 million which represents an 11.23% increase in operating revenues based upon a pro forma fully projected future test year ("FPFTY") ending December 31, 2017. 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 21, 2016, the Commission issued an Order initiating an investigation of Columbia's proposed general rate increase and suspending Columbia's Supplement No. 241 until December 19, 2016, unless otherwise directed by Order of the Commission.

4. Formal Complaints were filed on behalf of the OCA (C-2016-2535301), OSBA (C-2016-2538051), PSU (C-2016-2541623), CII (C-2016-2541753), Ralph Miller (C-2016-2538611), Michael Pikus (C-2016-2538843), Richard Collins (C-2016-2547479) and James Testrake (C-2016-2555931).

5. In addition, CAAP, CAUSE-PA, Direct Energy and the NGS Parties filed Petitions to Intervene.

6. A prehearing conference was scheduled for April 28, 2016. Joint Petitioners who participated in the prehearing conference filed prehearing memoranda identifying potential issues and witnesses.

7. The initial prehearing conference was held as scheduled on April 28, 2016. At the prehearing conference, ALJ Dunderdale established the litigation schedule. The ALJ also set forth discovery rules, which, pursuant to the Joint Petitioners' agreement,

included shorter response times than those provided in the Commission's regulations. See 52 Pa. Code §§ 5.341 *et seq.*

8. On April 29, 2016, the ALJ issued a Prehearing Order that confirmed the litigation schedule established at the Prehearing Conference.

9. On May 11, 2016, Columbia filed Supplement No. 245 to Tariff Gas Pa. PUC No. 9, suspending Columbia's Supplement No. 241 until December 19, 2016.

10. The Joint Petitioners conducted substantial formal and informal discovery in this proceeding. Pursuant to the established litigation schedule, I&E, OCA, Direct Energy, CII, OSBA, CAAP and the NGS Parties served direct testimony on June 16, 2016.

11. On July 13, 2016, I&E, OCA, OSBA, CAUSE-PA, PSU, CII, Direct Energy, the NGS Parties and Columbia served rebuttal testimony.

12. On July 26, 2016, OSBA, CII, I&E, OCA, PSU, Direct Energy, the NGS Parties and Columbia served surrebuttal testimony.

13. On July 27, 2016, Columbia filed a Motion for a Protective Order.

14. Columbia and PSU filed rejoinder outlines on August 1, 2016.

15. On July 28, 2016, the parties informed the ALJ that a partial settlement had been reached and requested that the first day of the evidentiary hearing be canceled to allow additional time for settlement negotiations on the remaining issues.

16. On July 28, 2016, the ALJ issued an Interim Order canceling the first day of the scheduled evidentiary hearing.

17. The ALJ issued a Protective Order in this proceeding on August 2, 2016.

18. On August 3, 2016, an evidentiary hearing was held for the purpose of submitting testimony and exhibits for the record by stipulation. The parties waived

cross-examination of all witnesses. Columbia's filing, testimony and exhibits and the testimony and exhibits served by the other parties during the course of the proceeding were formally introduced and admitted into the evidentiary record at the hearing.

19. The Joint Petitioners 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 have been able to agree to a settlement of all issues.

20. Joint Petitioners have agreed to a base rate increase, an allocation of that revenue increase to the rate classes, and a rate design for all rate classes to recover the portion of the rate increase allocated to such classes. Additionally, all other issues presented in the proceeding have been resolved by the Settlement. The Joint Petitioners are in full agreement that the Settlement is in the best interests of Columbia and its customers.

21. In the Settlement, the Joint Petitioners have proposed that rates be designed to produce an additional $35 million in annual base rate operating revenues instead of the Company's filed increase request of $55.3 million. Upon approval of the Settlement, Columbia will receive an increase in existing base rate operating revenues of approximately 7.12%, instead of the 11.23% increase proposed in Columbia's filing. A typical residential sales customer using 70 therms of gas purchased from Columbia per month will see an increase in their monthly bill from $77.33 to $83.05, or by 7.34%, instead of the monthly increase to $86.97, or 12.47%, that was originally proposed in the filing. The total bill for a small commercial customer using 158 therms of gas purchased from Columbia per month will increase from $128.29 to $136.07, or by 6.06%, instead of the monthly increase to $139.74, or 8.93% that was originally proposed in the filing.

The total bill for a small industrial customer using 1,328 therms of gas purchased from Columbia per month would increase from $898.48 to $952.17, or by 5.98%, instead of the monthly increase to $958.63, or 6.69% that was originally proposed in the filing.

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

III. SETTLEMENT[4]

23. 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, which resolves all issues in this proceeding, is in the public interest. The Joint Petitioners respectfully request that the 2016 Base Rate Filing, including those tariff changes included in Supplement No. 241 and specifically identified in Appendix "D" attached hereto, be approved subject to the terms and conditions of this Settlement specified below:

A. REVENUE REQUIREMENT

24. Rates will be designed to produce an increase in operating revenues of $35 million based upon the pro forma level of operations for the twelve months ended December 31, 2017.

25. As of the effective date of rates in this proceeding, Columbia will be eligible to include plant additions in the DSIC once eligible account balances exceed the levels projected by Columbia at December 31, 2017. 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.

26. 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

[4] The NGS Parties agree to the settlement terms related to natural gas supplier issues as set forth in paragraphs 50-57 of the Settlement but take no position on the remaining settlement terms.

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).

27. Columbia will continue to use normalization accounting with respect to the benefits of the tax repairs deduction. It is agreed that Columbia has completed the amortization of the $37.4 million tax refund previously received by Columbia, which is attributable to the change in method for the repairs deduction. Changes in the refund amount, above or below the $37.4 million, shall be reflected in accumulated deferred income taxes to be created under the normalization method of accounting.

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

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

(i) NIFIT – Continued amortization of non-Company labor start-up costs of the new financial software of $1,260,764, over a three-year period that began on December 18, 2015.

(ii) 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.

(iii) Corporate Services OPEB-Related Costs – Continuation of the previously-approved amortization of the regulatory asset of $903,131 associated with the transition of NiSource Corporate Services Company from a cash to accrual basis for OPEBs, over a ten-year period that began July 1, 2013.

30. 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 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.

31. 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 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.

32. On or before April 1, 2017, Columbia will provide the Commission's Bureau of Technical Utility Services ("TUS"), 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, 2016. On or before April 1, 2018, Columbia will update Exhibit No. 108, Schedule 1 filed

in this proceeding for the twelve months ending December 31, 2017. 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, 2017. 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.

33. For all future debt issuances during the twelve month periods ending December 31, 2016 and December 31, 2017, Columbia will provide to TUS, I&E, OCA and OSBA, within 60 days of issuance, all loan documentation filed with the Commission in compliance with orders in filings submitted by Columbia pursuant to Chapter 19 of the Pennsylvania Public Utility Code. In addition, Columbia will preserve and provide to I&E, OCA and OSBA as a part of its next base rate case the following: (1) all documentation supporting debt issued between this base rate case and the next base rate case; and (2) for each issuance the prevailing yield on U.S. utility bonds as reported by Bloomberg Finance L.P. for companies with a credit risk profile equivalent to that of NiSource Finance Corp.

34. The Company's Gas Procurement Charge ("GPC") shall continue at the current rate of $0.00695/therm.

35. The Merchant Function Charge ("MFC") shall be 1.52% for residential customers and 0.37% for non-residential customers. These are the charges as filed by Columbia. The revised MFC rates shall be reflected in the Purchase of Receivables ("POR") discount rates.

36. Tariff rates will go into effect on December 19, 2016.

37. Customers will not be charged separate processing fees for bill payments using third party debit card, credit card, Automated Clearinghouse ("ACH") or walk-in

locations. All processing fees will be considered "above-the-line" for ratemaking purposes. Parties reserve their rights to challenge in a future base rate proceeding the recovery of processing fees through rates, and Columbia reserves the right in response to cease payment of such third-party costs.

B. REVENUE ALLOCATION AND RATE DESIGN

38. The Residential customer charge will remain at the current $16.75/month.

39. Small General Service customer charges will remain at the current $21.25/month (≤6440 therms) and $48.00/month (>6440 therms).

40. Revenue allocation to the classes is set forth in Appendix "A." Rate design for all classes shall be as set forth in Appendix "B."[5] Revenue allocation and rate design reflect a compromise and do not endorse any particular cost of service study.

C. UNIVERSAL SERVICE AND CONSERVATION

41. Columbia may use the residential portion of pipeline penalty credits and refunds received through February 28, 2018, as a funding source for the Hardship Fund. Prior to February 28, 2018, Columbia may file a request with the Commission to continue to use the residential portion of pipeline credits and refunds to fund the Hardship Fund. Columbia agrees to continue to develop plans, in consultation with its Universal Service Advisory Council, to seek out additional funding from voluntary sources. Columbia will provide a report on ideas developed and implemented to increase voluntary contributions to the Hardship Fund as part of any request to continue applying pipeline credits and refunds to the Hardship Fund, as well as in its next base rate proceeding and Universal Service Plan proceeding. Further, Columbia commits to continue to explore joint outreach efforts with other regional public utilities

[5] Direct Energy takes no position with respect to the rate design set forth in Appendix "B".

and community agencies for funding of its Hardship Fund. Columbia will remove Hardship Fund recovery from the Rider USP.

42. Columbia's Low Income Usage Reduction Program ("LIURP") funding will continue at the level of $4.75 million per year as agreed to in the Commission-approved settlement of Columbia's base-rate proceeding at Docket No. R-2014-2406274, which provides that parties agreed not to propose any further change to LIURP funding for a period of three years commencing with the effective date of rates in that proceeding. Any unspent funds will be carried over and added to the following year's funding.

43. Columbia agrees to continue to partner with Community Based Organizations ("CBOs"), including member agencies of CAAP and Pennsylvania Weatherization Providers in the development, implementation and administration of its LIURP program.

44. Columbia agrees to extend its Third Party Notification Program to include all Customer Assistance Program ("CAP") reminder notices, including notices of potential CAP removal such as income verification requests. Additionally, Columbia agrees to make Third Party Notification forms available at local CBOs, and will encourage CBOs to include Third Party Notification forms in processing other assistance. Customers should be informed that completion of a Third Party Notification form is completely voluntary.

45. Columbia agrees to provide brochures on all programs to non-utility access points, such as CBOs. Columbia shall authorize and encourage CBOs to disseminate brochures to applicants for other assistance.

46. Columbia agrees to reduce the base participation level for its CAP from 25,300 to 23,000. Further, the universal service cost offset will remain 7.5%.

47. Columbia agrees to review the list of customers with high CAP credits (over $1,000) from the prior year and prioritize those customers for weatherization when possible. Once this list has been exhausted, Columbia will use the high usage CAP customer list as well as eligible customers requesting weatherization.

D. PROGRAMS TO EXPAND THE AVAILABILITY OF GAS SERVICE

48. Columbia's Large Customer Incentive ("LCI") proposal is approved with the following modification: customers participating in the program will be required to pay 30% of the uneconomic portion upfront or have a repayment period that does not exceed ten (10) years. Columbia agrees to provide the following information related to Columbia's LCI proposal, as applicable:

a) Main and service investment per project;

b) Net Present Value ("NPV") model results for each project, inclusive of the main and service allowances;

c) Required LCI deposit by project;

d) Number of customers connected by each project and number of subsequent connections;

e) Annual non-gas revenues received by project, separated into base rate and LCI repayment revenues (principal and interest stated separately);

f) Annual usage by project;

g) Average investment cost per customer by project; and

h) Number of new service requests for projects in which the NPV model is run, but the project does not proceed to construction.

49. Columbia agrees to withdraw its proposed multi-unit incentive proposal. Columbia reserves the right to present this proposal in a future proceeding and all parties reserve their rights to support or oppose such proposal if filed.

E. NATURAL GAS SUPPLIER ISSUES[6]

50. Effective upon approval of the Settlement, Columbia agrees to remove the designation of enrollment type from its NGS customer submission procedure.

51. Columbia agrees to utilize pages 4 and 5 of the existing customer application, plus an additional page requiring updated contact information (emergency, billing and mailing), as a shortened version of the agency form for GDS customers who seek to change their NGS supplier (as further modified per paragraph 52, below). This shortened agency form shall be effective for contracts rendered on or after thirty (30) days after the entry of the Commission Order approving this Settlement.

52. As soon as possible, but in no event no later than six months following the entry of a Commission Order approving the Settlement, Columbia agrees to modify its supplier agency form (pages 4-5) and its Aviator Agreement to include authorization for the supplier to have access to all of the customer's usage information on the Aviator system, or a comparable current or future system and to obtain revised authorization forms from all current customers. Columbia shall insure that a customer's Aviator data shall be available to the customer's current supplier.

53. With respect to the calculation of penalties for over and under deliveries during an operational order, Columbia shall adopt an index-based penalty structure. The revised penalty structure, for non-compliance with Operational Flow Orders

[6] The OCA takes no position on the settlement terms regarding natural gas supplier issues as set forth in paragraphs 50-57 of the Settlement.

("OFOs") and Operational Matching Orders ("OMOs"), as well as the non-compliance charges related to Choice deliveries, shall be 3 times the highest of the midpoint prices reflected in Platts Gas Daily for the day of the OMO or OFO non-compliance, from the applicable indices, depending upon the market area utilized, as set forth on Appendix "C". In the event no midpoint prices are published in Platts Gas Daily on a particular day, the highest price paid by Columbia on that day shall be used as the index price. Columbia shall update the applicable indices on 60 days' notice to Customer Proxies in the event of a change in applicable indices.

54. Within ninety (90) days of the entry of an Order by the Commission approving this Settlement:

a) Columbia agrees to propose in a non-general tariff filing that all customers eligible to be served on Rate Schedules SDS, LDS and MLDS [Small Distribution Service, Large Distribution Service, and Main Line Distribution Service] must have installed Electronic Flow Correctors ("EFC") and telephonic equipment to transmit daily usage information to Columbia. Columbia further agrees to propose that it install, own, operate and maintain all equipment, including telephonic or similar technology, provided that Columbia is granted rate recovery of reasonable and prudent capital and operating and maintenance costs to own, operate and maintain the capability to obtain daily information from such customers. To the extent that any associated costs will not be rate based, Columbia shall be permitted to seek to create a regulatory asset for such costs and propose to recover them in its next base rate case. All Parties retain their rights to support or oppose such proposal in the non-general rate filing. Issues related to cost allocation and rate recovery of the costs associated with this equipment will be addressed in the Company's next base rate proceeding.

b) For customers who have EFC and operating telephonic equipment to transmit daily usage information installed, Columbia agrees on a commercially reasonable basis to provide customer usage data in the GTS0005 Reports and in the Aviator-EMDCS data base by 1 PM following the day for which the data is being provided.

55. Subsequent to the Commission's approval of the non-general tariff filing and Columbia's installation of equipment to obtain daily information, as addressed in Paragraph 54, above, in addition to any other remedy a supplier may have, a supplier shall be subject to Modified OMO Penalties with respect to any OMO customer with an EFC and operating telephone equipment for which Columbia does not have daily usage data available, by the end of an OMO Period. An OMO Period is defined as one or more OMO days issued within a calendar month. Modified OMO penalties shall mean the penalty that would otherwise be applicable pursuant to paragraph 53 except that the penalty multiplier shall be 1.5 times rather than 3 times.

56. Proposed Rules Applicable to Distribution Service ("RADS") 2.7.2 shall be withdrawn, to be discussed as part of the collaborative to be held pursuant to Paragraph 57.[7]

57. Within sixty (60) days of the entry of a Commission order approving this Settlement, Columbia shall convene a collaborative with the parties to this proceeding and all interested Suppliers on its system to discuss new approaches to deal with

[7] The NGS Parties, for purposes of this settlement only, are not opposing inclusion of RADS 4.9.5 in the tariff at this time.

ongoing pipeline delivery constraints, including the creation of new market "orders". The Collaborative shall conclude within 120 days of its initiation, unless extended by consensus of the parties participating. Any resolutions requiring tariff changes shall be reflected in a proposed non-general tariff filing by Columbia at the conclusion of the collaborative. Without limitation to other issues that may be addressed in the collaborative, the parties will address how transparency may be achieved as to Columbia's nominations to alternate delivery points under RADS 4.9.5, including information that Columbia could share with suppliers regarding actual nominations. At the conclusion of the collaborative, Columbia will file a letter report with the Commission summarizing the results and consensus recommendations of the collaborative.

F. OTHER

58. Columbia will continue its efforts to reduce restoration costs, through efforts including, but not limited to, coordinating pipe replacement projects with other street projects, using private rights-of-way, avoiding temporary restoration, and replacing pipe using trenchless construction techniques, all where technically, operationally and economically feasible.

59. Except as otherwise modified by this Settlement, the Company's proposed tariff revisions are approved.

IV. SETTLEMENT IS IN THE PUBLIC INTEREST

60. 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 outlines by a number of the Joint Petitioners that were admitted into the record by stipulation.

61. 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.

62. Joint Petitioners have submitted, along with this Settlement, 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. The Joint Petitioners' Statements in Support are attached hereto as Appendices "E" through "N".

V. CONDITIONS OF SETTLEMENT

63. 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.

64. 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.

65. 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.

66. 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.

67. 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.

68. This Settlement is being presented only in the context of these proceedings in an effort to resolve the proceedings in a manner which 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.

69. 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.

70. If the ALJ adopts the Settlement without modification, the Joint Petitioners waive their individual rights to file exceptions with regard to the Settlement.

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

1. That the Honorable Administrative Law Judge Katrina L. Dunderdale and the Commission approve this Settlement including all terms and conditions thereof, without modification;

2. That the Commission's investigation at Commission Docket R-2016-2529660 and the complaints of OCA, OSBA, PSU, CII at Docket Nos. C-2016-2535301, C-2016-2538051, C-2016-2541623, and C-2016-2541623, respectively, shall be marked closed.

3. That the customer complaints of Ralph Miller (C-2016-2538611), Michael Pikus (C-2016-2538843), Richard Collins (C-2016-2547479) and James Testrake (C-2016-2555931) associated with this proceeding be dismissed.

4. That the Commission enter an Order consistent with the Settlement, terminating the proceeding and authorizing Columbia Gas of Pennsylvania, Inc. to file the form of tariff supplement attached as Appendix "D" as provided herein, effective for service rendered on and after December 19, 2016.

Respectfully submitted,

Michael W. Hassell

Michael W. Hassell, Esquire
Lillian S. Harris, Esquire
Lindsay A. Berkstresser, Esquire
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101-1601

Date: 9/2/2016

And

14640978v1

Theodore J. Gallagher, Esquire
Meagan Bielanin Moore, Esquire
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Appendix A

Columbia Gas of Pennsylvania, Inc.
Increase by Rate Class
For the 12 Months Ending December 31, 2017

Appendix A

	Amount	RS/RDS	SGSS/SCD/SGDS	SDS/LGSS	LDS/LGSS	MDS/NSS
Settlement Increase	$35,000,000	$25,900,000	$6,200,000	$1,800,000	$1,100,000	$0

Appendix B

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2017

Exhibit No. 103
Schedule No. 8

Witness: M. J. Bell

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, RDGSS	3,463,638	24,297,875.3	$268,442,827	$19,710,436	$288,153,263	7.34%	7.22%
3	Small General Service (≤ 6,440 Therms Annually) - SGSS	274,880	4,337,144.6	$35,221,018	$2,138,646	$37,359,664	6.07%	6.63%
4	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS	42,773	4,765,070.5	$32,571,951	$1,926,042	$34,497,993	5.91%	6.65%
5	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS	1,022	884,981.2	$4,975,381	$231,124	$5,206,505	4.65%	9.08%
6	Large General Sales Service (> 540,000 Therms Annually) - LGSS	24	73,145.4	$362,773	$10,829	$373,602	2.99%	6.25%
7	Negotiated Sales Service - NSS	12	65,000.0	$292,015	$0	$292,015	0.00%	0.00%
8	Residential Distribution Service (Choice) - RDS, RDGDS, RCC	1,271,203	10,105,793.7	$89,545,860	$6,127,805	$95,673,665	6.84%	7.22%
9	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD	90,425	1,376,587.2	$7,883,118	$678,795	$8,561,913	8.61%	6.63%
10	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCI	10,157	1,023,436.7	$4,541,778	$413,673	$4,955,451	9.11%	6.65%
11	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS	8,171	158,612.7	$731,855	$90,581	$822,436	12.38%	6.63%
12	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS	19,658	3,293,046.8	$12,165,172	$936,075	$13,101,247	7.69%	6.65%
13	Small Distribution Service - SDS	5,446	6,341,013.6	$14,807,046	$1,564,504	$16,371,550	10.57%	9.08%
14	Large Distribution Service - LDS	1,118	20,981,336.3	$17,189,937	$1,086,258	$18,276,195	6.32%	6.25%
15	Main Line Distribution Service Class I - MLDS	36	2,779,000.0	$386,109	$0	$386,109	0.00%	0.00%
16	Main Line Distribution Service Class II - MLDS	72	2,402,000.0	$970,340	$0	$970,340	0.00%	0.00%
17	Other Gas Department Revenue			$1,747,013	$85,190	$1,832,203	4.88%	4.88%
18	Total Revenues	5,188,635	82,884,044.0	$491,834,193	$ 34,999,958	$ 526,834,151	7.12%	7.12%
19	**Base Rates Revenue Only**							
20	Residential Sales - RS, RDGSS	3,463,638	24,297,875.3	$174,174,360	$18,247,704	$192,422,064	10.48%	9.81%
21	Small General Service (≤ 6,440 Therms Annually) - SGSS	274,880	4,337,144.6	$21,428,464	$2,138,646	$23,567,110	9.98%	10.03%
22	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS	42,773	4,765,070.5	$17,418,550	$1,926,042	$19,344,592	11.06%	10.03%
23	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS	1,022	884,981.2	$2,170,964	$231,124	$2,402,088	10.65%	10.58%
24	Large General Sales Service (> 540,000 Therms Annually) - LGSS	24	73,145.4	$130,982	$10,829	$141,811	8.27%	6.33%
25	Negotiated Sales Service - NSS	12	65,000.0	$19,879	$0	$19,879	0.00%	0.00%
26	Residential Distribution Service (Choice) - RDS, RDGDS, RCC	1,271,203	10,105,793.7	$69,604,408	$5,673,054	$75,277,462	8.15%	9.81%
27	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD	90,425	1,376,587.2	$6,868,848	$678,795	$7,547,643	9.88%	10.03%
28	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCI	10,157	1,023,436.7	$3,787,710	$413,673	$4,201,383	10.92%	10.03%
29	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS	8,171	158,612.7	$708,598	$90,581	$799,179	12.78%	10.03%
30	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS	19,658	3,293,046.8	$11,464,988	$936,075	$12,401,063	8.16%	10.03%
31	Small Distribution Service - SDS	5,446	6,341,013.6	$14,807,046	$1,564,504	$16,371,550	10.57%	10.58%
32	Large Distribution Service - LDS	1,118	20,981,336.3	$17,189,937	$1,086,258	$18,276,195	6.32%	6.33%
33	Main Line Distribution Service Class I - MLDS	36	2,779,000.0	$386,109	$0	$386,109	0.00%	0.00%
34	Main Line Distribution Service Class II - MLDS	72	2,402,000.0	$970,340	$0	$970,340	0.00%	0.00%
35	Total Base Rates Revenues	5,188,635	82,884,044.0	$341,131,183	$32,997,285	$374,128,468	9.67%	9.67%

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2017

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	**STAS**							
2	Residential Sales - RS, RDGSS			$0	$0	$0	0.00%	0.00%
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, RDGDS, RCC			$0	$0	$0	0.00%	0.00%
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	Total STAS			$0	$0	$0	0.00%	0.00%
18	**Rider CC**							
19	Residential Sales - RS, RDGSS			$24,298	$0	$24,298	0.00%	0.00%
20	Small General Service (≤ 6,440 Therms Annually) - SGSS			$4,337	$0	$4,337	0.00%	0.00%
21	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$4,765	$0	$4,765	0.00%	0.00%
22	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			$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	Negotiated Sales Service - NSS			$0	$0	$0	0.00%	0.00%
25	Residential Distribution Service (Choice) - RDS, RDGDS, RCC			$7,554	$0	$7,554	0.00%	0.00%
26	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD			$1,377	$0	$1,377	0.00%	0.00%
27	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD			$1,023	$0	$1,023	0.00%	0.00%
28	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS			$158	$0	$158	0.00%	0.00%
29	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS			$3,272	$0	$3,272	0.00%	0.00%
30	Small Distribution Service - SDS			$0	$0	$0	0.00%	0.00%
31	Large Distribution Service - LDS			$0	$0	$0	0.00%	0.00%
32	Main Line Distribution Service Class I - MLDS			$0	$0	$0	0.00%	0.00%
33	Main Line Distribution Service Class II - MLDS			$0	$0	$0	0.00%	0.00%
34	Total Rider CC			$46,784	$0	$46,784	0.00%	0.00%

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2017

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	**Gas Procurement Charge**							
2	Residential Sales - RS, RDGSS			$1,688,702	$0	$1,688,702	0.00%	0.00%
3	Small General Service (≤ 6,440 Therms Annually) - SGSS			$301,432	$0	$301,432	0.00%	0.00%
4	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$331,172	$0	$331,172	0.00%	0.00%
5	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			$61,506	$0	$61,506	0.00%	0.00%
6	Large General Sales Service (> 540,000 Therms Annually) - LGSS			$5,084	$0	$5,084	0.00%	0.00%
7	Negotiated Sales Service - NSS			$0	$0	$0	0.00%	0.00%
8	Residential Distribution Service (Choice) - RDS, RDGDS, RCC			$0	$0	$0	0.00%	0.00%
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	Total Gas Procurement Charge			$2,387,896	$0	$2,387,896	0.00%	0.00%
18	**Universal Service Plan Rider**							
19	Residential Sales - RS, RDGSS			$16,235,840	$1,462,732	$17,698,572	9.01%	9.01%
20	Small General Service (≤ 6,440 Therms Annually) - SGSS			$0	$0	$0	0.00%	0.00%
21	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$0	$0	$0	0.00%	0.00%
22	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			$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	Negotiated Sales Service - NSS			$0	$0	$0	0.00%	0.00%
25	Residential Distribution Service (Choice) - RDS, RDGDS, RCC			$5,047,583	$454,751	$5,502,334	9.01%	9.01%
26	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD			$0	$0	$0	0.00%	0.00%
27	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD			$0	$0	$0	0.00%	0.00%
28	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS			$0	$0	$0	0.00%	0.00%
29	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS			$0	$0	$0	0.00%	0.00%
30	Small Distribution Service - SDS			$0	$0	$0	0.00%	0.00%
31	Large Distribution Service - LDS			$0	$0	$0	0.00%	0.00%
32	Main Line Distribution Service Class I - MLDS			$0	$0	$0	0.00%	0.00%
33	Main Line Distribution Service Class II - MLDS			$0	$0	$0	0.00%	0.00%
34	Total Universal Service Charge			$21,283,423	$1,917,483	$23,200,906	9.01%	9.01%

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2017

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	**Merchant Function Charge**							
2	Residential Sales - RS, RDGSS			$1,010,792	$0	$1,010,792	0.00%	0.00%
3	Small General Service (≤ 6,440 Therms Annually) - SGSS			$44,239	$0	$44,239	0.00%	0.00%
4	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$48,604	$0	$48,604	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, RDGDS, RCC			$0	$0	$0	0.00%	0.00%
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	Total Merchant Function Charge			$1,103,635	$0	$1,103,635	0.00%	0.00%
18	**Gas Cost**							
19	Residential Sales - RS, RDGSS			$75,308,835	$0	$75,308,835	0.00%	0.00%
20	Small General Service (≤ 6,440 Therms Annually) - SGSS			$13,442,546	$0	$13,442,546	0.00%	0.00%
21	Small General Service (> 6,440 to ≤ 64,400 Therms Annually) - SGSS			$14,768,860	$0	$14,768,860	0.00%	0.00%
22	Large General Sales Service (≤ 540,000 Therms Annually) - LGSS			$2,742,911	$0	$2,742,911	0.00%	0.00%
23	Large General Sales Service (> 540,000 Therms Annually) - LGSS			$226,707	$0	$226,707	0.00%	0.00%
24	Negotiated Sales Service - NSS			$272,136	$0	$272,136	0.00%	0.00%
25	Residential Distribution Service (Choice) - RDS, RDGDS, RCC			$14,886,315	$0	$14,886,315	0.00%	0.00%
26	Small Commercial Distribution Service (Choice ≤ 6,440 Therms Annualy) - SCD			$1,012,893	$0	$1,012,893	0.00%	0.00%
27	Small Commercial Distribution Service (Choice > 6,440 to ≤ 6,440 Therms Annualy) - SCD			$753,045	$0	$753,045	0.00%	0.00%
28	Small General Distribution Service (≤ 6,440 Therms Annually) - SGDS			$23,099	$0	$23,099	0.00%	0.00%
29	Small General Distribution Service (> 6,440 to ≤ 64,400 Therms Annually) - SGDS			$696,912	$0	$696,912	0.00%	0.00%
30	Small Distribution Service - SDS			$0	$0	$0	0.00%	0.00%
31	Large Distribution Service - LDS			$0	$0	$0	0.00%	0.00%
32	Main Line Distribution Service Class I - MLDS			$0	$0	$0	0.00%	0.00%
33	Main Line Distribution Service Class II - MLDS			$0	$0	$0	0.00%	0.00%
34	Total Gas Cost			$124,134,259	$0	$124,134,259	0.00%	0.00%

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2017

Exhibit No. 103
Schedule No. 8

Witness: M. J. Bell

Line No.	Description	Total (1)	RS/RDG/RGSS RDS/ RDGDS/RCC (2)	SGSS1/SCD1/SGDS1 (3)	SGSS2/SCD2/SGDS2 (3)	SDS/LGS (4)	LDS/LGS (5)	MDS/NSS (6)
1	**Determination of Revenue Distribution**							
2	Rate Base (Exhibit 111, Schedule 1, Page 2, Line 12)	$1,494,091,076	$1,070,399,333	$130,990,065	$133,748,886	$65,101,517	$93,067,863	$783,412
3								
4	Unitized Return @ Current Rates (Exhibit 111, Schedule 1, Page 2, Line 14)	1.00000	0.90495	1.04803	1.41797	1.58472	0.88682	16.50730
5	**Proposed Unitized Return**	**1.00000**	**0.95500**	**1.00374**	**1.24073**	**1.36482**	**0.81853**	**12.06150**
6	**Change in Unitized Return**	**0.00000**	**0.05005**	**(0.04429)**	**(0.17724)**	**(0.21990)**	**(0.06829)**	**(4.44580)**
7	Rate of Return Requested	8.150%	7.783%	8.180%	10.112%	11.123%	6.671%	98.301%
8	Net Operating Income @ Requested Return (Line 2 x Line 7)	$121,768,423	$83,309,180	$10,714,987	$13,524,687	$7,241,242	$6,208,225	$770,102
9	Net Operating Income @ Current Rates (Exhibit 111, Sch. 1, Page 2, Line 11)	$88,978,983	$57,681,506	$8,175,384	$11,293,776	$6,143,577	$4,914,638	$770,102
10	Income Deficiency (Line 8 - Line 9)	$32,789,440	$25,627,674	$2,539,603	$2,230,911	$1,097,665	$1,293,587	$0
11	Gross Converstion Factor	1.68520727	1.68520727	1.68520727	1.68520727	1.68520727	1.68520727	1.68520727
12	**Revenue Required Increase (Exhibit 102 Sch. 3 Page 3)**	**55,257,001**	**43,187,942**	**4,279,757**	**3,759,547**	**1,849,793**	**2,179,962**	**0**
13	Revenue Requirement Change Due to Settlement	(20,257,001)	(17,287,942)	(1,363,983)	(475,321)	(49,793)	(1,079,962)	0
14	**Revenue Required Increase per Settlement**	**35,000,000**	**25,900,000**	**2,915,774**	**3,284,226**	**1,800,000**	**1,100,000**	**0**
15	**Percent Distribution to Rate Classes**	**100.00%**	**74.01%**	**8.33%**	**9.38%**	**5.14%**	**3.14%**	**0.00%**
16	Less: Proposed Change in STAS (Page 1 Line 1 through Line 17)	0	0	0	0	0	0	0
17	Less: Proposed Change Other Gas Department Revenue (Page 1 Line 17)	85,190	63,041	7,097	7,994	4,381	2,677	0
18	Less: Proposed Change in Rider CC (Page 2 Line 18 through Line 34)	0	0	0	0	0	0	0
19	Less: Proposed Change in Gas Procurement Revenue (Page 2 Line 5 through Line 17)	0	0	0	0	0	0	0
20	**Proposed Increase to Base Revenue**	**$34,914,810**	**$25,836,959**	**$2,908,677**	**$3,276,232**	**$1,795,619**	**$1,097,323**	**$0**
21	**Percent Distribution to Rate Classes**	**100.00%**	**74.01%**	**8.33%**	**9.38%**	**5.14%**	**3.14%**	**0.00%**
22	**Current Base Revenue**	**$341,131,183**	**$243,778,768**	**$29,005,910**	**$32,671,248**	**$16,978,010**	**$17,320,919**	**$1,376,328**
23	**Current Percent Distribution of Rate Classes**	**100.00%**	**71.46%**	**8.50%**	**9.58%**	**4.98%**	**5.08%**	**0.40%**
24	**Proposed Base Revenue**	**$376,045,993**	**$269,615,727**	**$31,914,587**	**$35,947,480**	**$18,773,629**	**$18,418,242**	**$1,376,328**
25	**Proposed Percent Distribution of Rate Classes**	**100.00%**	**71.70%**	**8.49%**	**9.56%**	**4.99%**	**4.90%**	**0.37%**

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2017

Line No.			Bills	Dth	Proposed Rate $	Proposed Revenue $	Current Revenue $	Percent of Current Revenue %	Current Rate $	Proposed Inc. (Dec.) $
1		**Residential Rate Design (RS, RGS, RDS, RDGDS, RCC)**								
2		Total Revenue @ Current Rates				$357,988,687				
3	Less:	STAS				0				
4	Less:	Gas Cost Revenue				90,195,150				
5	Less:	Gas Procurement Charge				1,688,702				
6	Less:	Rider CC				31,852				
7	Less:	Merchant Function Charge				1,010,792				
8	Less:	Rider USP				21,283,423				
9	Plus:	Proposed Increase to Base Rates				25,836,959				
10		Proposed Base Revenue				$269,615,727				
11	Less:	Customer Charge Revenue (Exhibit 103, Sch. 1)	4,734,841		**16.75**	79,308,587	79,308,588	32.53%	16.75	(1)
12		Net Volumetric Gas Revenue				190,307,140				
13		All Gas Consumed (Exhibit 103, Sch. 1)		34,403,669.0	**5.5316**	$190,307,335	$164,470,180	67.47%	4.7806	25,837,155
14		Total Base Revenue Charge						100.00%		**$25,837,154**
15		**Rider USP - Universal Service Plan**								
16		Universal Service Plan Rider @ Current Rate				21,283,423				
17	Plus:	Redistribution of CAP shortfall resulting from proposed rates				1,916,397				
18		Expected Change in Universal Service Plan Rider Rate		31,851,875.3	0.7284	$23,199,820			0.6682	

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2017

Exhibit No. 103
Schedule No. 8

Witness: M. J. Bell

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				$43,835,991				
3	Less:	STAS				0				
4	Less:	Gas Cost Revenue				14,478,538				
5	Less:	Gas Procurement Charge				301,432				
6	Less:	Rider CC				5,872				
7	Less:	Merchant Function Charge				44,239				
8	Less:	Rider USP				0				
9	Plus:	Proposed Increase to Base Rates				2,908,677				
10		Proposed Base Revenue				$31,914,587				
11	Less:	Less Flex Revenue (SGDS1)				$3,645				
12	Less:	Customer Charge Revenue (Exhibit 103, Sch. 1) ≤ 6,440 Thms	373,440		**21.25**	7,935,600	7,935,600	27.36%	21.25	-
13		Net Volumetric Gas Revenue				$23,975,342				
14		All Gas Consumed Rate		5,871,344.5	4.0835	23,975,635				
15		SGSS1,SCD1 @ uniform rate		5,713,731.8	4.0835	23,332,024				
16		SGDS1 @ uniform rate		157,612.7	4.0835	643,611				
17		Intra-Class Adjustment - SGDS1 to SGSS1/SCD1 (Exhibit MPB-4)				20,958				
18		Less Than 6,440 Therms Annually - SGSS1, SCD1		5,713,731.8	**4.0870**	23,352,982	20,534,581	70.80%	3.5939	2,818,401
19		Less Than 6,440 Therms Annually - SGDS1		157,612.7	**3.9506**	622,653	532,084	1.84%	3.3759	90,569
20		Total Base Revenue Charge				31,911,235	$29,002,265	100.00%		**$2,908,970**

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2017

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				$49,278,901				
3	Less:	STAS				0				
4	Less:	Gas Cost Revenue				16,218,817				
5	Less:	Gas Procurement Charge				331,172				
6	Less:	Rider CC				9,060				
7	Less:	Merchant Function Charge				48,604				
8	Less:	Rider USP				0				
9	Plus:	Proposed Increase to Base Rates				3,276,232				
10		Proposed Base Revenue				$35,947,480				
11	Less:	Less Flex Revenue (SGDS2)				$34,665				
12	Less:	Customer Charge Revenue (Exhibit 103, Sch. 1) > 6,440 to ≤ 64,440 Thms	72,516		**48.00**	3,480,768	3,480,768	10.67%	48.00	-
13		Net Volumetric Gas Revenue				$32,432,047				
14		All Gas Consumed Rate		9,060,354.0	3.5796	32,432,443				
15		SGSS2,SCD2 @ uniform rate		5,788,507.2	3.5796	20,720,540				
16		SGDS2 @ uniform rate		3,271,846.8	3.5796	11,711,903				
17		Intra-Class Adjustment - SGDS2 to SGSS2/SCD2 (Exhibit MPB-4)				285,163	306,121			
18		6,440 - 64,400 Therms Annually - SGSS2, SCD2		5,788,507.2	**3.6288**	21,005,703	18,665,620	57.19%	3.2246	2,340,083
19		6,440 - 64,400 Therms Annually - SGDS2		3,271,846.8	**3.4923**	11,426,740	10,490,195	32.14%	3.2062	936,545
20		Total Base Revenue Charge				$32,432,443	$29,155,815	100.00%		**$3,276,628**

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2017

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				$19,782,427				
3	Less: STAS				0				
4	Less: Gas Cost Revenue				2,742,911				
5	Less: Gas Procurement Charge				61,506				
6	Plus: Proposed Increase to Base Rates				1,795,619				
7	Proposed Base Revenue				$18,773,629				
8	Less: Flex Revenue				256,411				
9	Less: Customer Charge Revenue (Exhibit 103, Sch. 1) > 64,400 to ≤ 110,000 Thms	3,159		229.75	725,780	679,185		215.00	46,595
10	Less: Customer Charge Revenue (Exhibit 103, Sch. 1) > 110,000 to ≤ 540,000 Thms	3,189		757.34	2,415,157	2,184,465		685.00	230,692
11	Net Volumetric Gas Revenue				$15,376,281				
12	> 64,400 to ≤ 110,000 Therms Annually (Exhibit 103, Sch. 1)		1,898,905.3	2.3050	4,376,992	3,944,786	28.47%	2.0774	432,206
13	> 110,000 to <= 540,000 Therms Annually (Exhibit 103, Sch. 1)		5,104,089.5	2.1550	10,999,289	9,913,163	71.53%	1.9422	1,086,126
14	Total Base Revenue Charge				$15,376,281	$13,857,949	100.00%		$1,518,332
									$1,795,619
15	**Large Distribution Service Rate Design (LDS/LGSS)**								
16	Total Revenue @ Current Rates				$17,552,710				
17	Less: STAS				0				
18	Less: Gas Cost Revenue				226,707				
19	Less: Gas Procurement Charge				5,084				
20	Plus: Proposed Increase to Base Rates				1,097,323				
21	Proposed Base Revenue				$18,418,242				
22	Less: Flex Revenue				4,087,013				
23	Less: Customer Charge Revenue (Exhibit 103, Sch. 1)								
24	> 540,000 to ≤ 1,074,000 Thms	530		1,947.06	1,031,942	954,000		1,800.00	77,942
25	> 1,074,000 to ≤ 3,400,000 Therms Annually	336		3,028.76	1,017,663	940,800		2,800.00	76,863
26	> 3,400,000 to ≤ 7,500,000 Therms Annually	48		5,841.18	280,377	259,200		5,400.00	21,177
27	> 7,500,000 Therms Annually	12		8,653.60	103,843	96,000		8,000.00	7,843
28	Net Volumetric Gas Revenue				$11,897,404				
29	Usage Charge (Exhibit 103, Sch. 1)								
30	> 540,000 to ≤ 1,074,000 Thms		3,216,481.7	1.2999	4,181,133	3,860,100	35.14%	1.2001	321,033
31	> 1,074,000 to ≤ 3,400,000 Therms Annually		4,804,000.0	1.1530	5,539,162	5,113,858	46.56%	1.0645	425,304
32	> 3,400,000 to ≤ 7,500,000 Therms Annually		1,628,000.0	1.0347	1,684,572	1,555,228	14.16%	0.9553	129,344
33	> 7,500,000 Therms Annually		800,000.0	0.6157	492,538	454,720	4.14%	0.5684	37,818
34	Total Base Revenue Charge				$11,897,405	$10,983,906	100.00%		$913,499
									$1,097,324

Columbia Gas of Pennsylvania, Inc.
Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement
For the 12 Months Ended December 31, 2017

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				$1,648,464				
3	Less:	STAS				0				
4	Less:	Gas Cost Revenue				272,136				
5	Plus:	Proposed Increase to Base Rates				<u>0</u>				
6		Proposed Base Revenue				$1,376,328				
7	Less:	Flex Revenue				1,273,154				
8	Less:	MDS I Customer Charge Revenue (Exhibit 103, Sch. 1)								
9		> 274,000 to ≤ 540,000 Thms	0		**469.34**	0	0		469.34	0
10		> 540,000 to ≤ 1,074,000 Therms Annually	24		**1,149.00**	27,576	27,576		1,149.00	0
11		> 1,074,000 to ≤ 3,400,000 Therms Annually	12		**2,050.00**	24,600	24,600		2,050.00	0
12		> 3,400,000 to ≤ 7,500,000 Therms Annually	0		**4,096.00**	0	0		4,096.00	0
13		> 7,500,000 Therms Annually	0		**7,322.00**	0	0		7,322.00	0
14	Less:	MDS II Customer Charge Revenue (Exhibit 103, Sch. 1)								
15		> 2,146,000 to ≤ 3,400,000 Therms Annually	12		**2,050.00**	24,600	24,600		2,050.00	-
16		> 3,400,000 to ≤ 7,500,000 Therms Annually	0		**4,096.00**	0	0		4,096.00	-
17		> 7,500,000 Therms Annually	0		**7,322.00**	<u>0</u>	0		7,322.00	-
18		Net Volumetric Gas Revenue				$26,398				
19		MDS I Usage Charge (Exhibit 103, Sch. 1)		167,000.0	**0.0937**	15,648	15,648	59.28%	0.0937	-
20		MDS II Usage Charge (Exhibit 103, Sch. 1)								
21		> 2,146,000 to ≤ 3,400,000 Therms Annually		24,000.0	**0.4479**	10,750	10,750	40.72%	0.4479	0
22		> 3,400,000 to <= 7,500,000 Therms Annually		0.0	**0.3874**	0	0	0.00%	0.3874	0
23		> 7,500,000 Therms Annually		0.0	**0.3355**	0	0	<u>0.00%</u>	0.3355	0
24								100.00%		
25		Total Base Revenue Charge								**$0**

Appendix C

2. RULES APPLICABLE TO ALL DISTRIBUTION SERVICE - continued

2.22 Platts "Gas Daily", Daily Price Survey - Designation by Pipeline Scheduling Point (C)

The table below will be used to identify the specific price indices for each pipeline scheduling point, the higher of which will be used as the starting point for calculating charges for non-compliance with Operational Flow Orders, Operational Matching Orders and/or failure to deliver the Choice Daily Delivery Requirement. The physical location of the customer's service address will determine the pipeline scheduling point used in calculating the non-compliance charge(s).

Platts "Gas Daily", Daily Price Survey				
Pipeline Scheduling Point	Columbia Gas, App.	Dominion North Point	Tennessee Zone 4 – 200 Leg	Texas Eastern M-3
25 - Lancaster	X			X
26 - Bedford	X		X	
29 - Downington	X			X
35 - Pittsburgh	X		X	
36 - Olean	X			X
38 - Rimersburg	X		X	
39 - New Castle	X		X	
40 - PA/WV Misc	X		X	

(C) Indicates Change

Appendix D

COLUMBIA GAS OF PENNSYLVANIA, INC.

121 Champion Way, Suite 100 Canonsburg, Pennsylvania

RATES AND RULES

FOR

FURNISHING GAS SERVICE

IN

THE TERRITORY AS DESCRIBED HEREIN

ISSUED: EFFECTIVE:

ISSUED BY: MARK KEMPIC, PRESIDENT
121 CHAMPION WAY, SUITE 100
CANONSBURG, PENNSYLVANIA 15317

NOTICE

This Tariff Supplement Makes Rate Increases and Changes to the Existing Tariff - See "List of Changes Made by This Tariff Supplement" on Page Nos. 2 through 2e

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
Cover	Tariff Cover Page	Supplement No., Issue and Effective Date.
2 – 2e	List of Changes	List of Changes.
3	Table of Contents	Added the label "Other Rates Summary" for page 20. Revised the label for page 21. Removed "Held for Future Use" for page 29.
5	Table of Contents	Added 2.22 Platts "Gas Daily" Daily Price Survey – Designation by Market Area. Moved "Held for Future Use 215 - 224" to page 6.
6	Table of Contents	Added "Held for Future Use 215 – 224" from page 5.
16	Rate Summary	The Distribution Charge has increased. The Gas Supply Cost has decreased. The "Pass-through Charge" has decreased. The "Total Effective Rate" has increased.
17	Rate Summary	The Distribution Charge has increased. The Gas Supply Cost has decreased. The "Total Effective Rate" has increased.
18	Rate Summary	The Customer Charge has increased. The Distribution Charge has increased. The "Total Effective Rate" has increased.
20	Other Rates Summary	The Price-to-Compare has decreased.
21	Rider Summary	The "Universal Service Plan – Rider USP" has increased. The Merchant Function Charge has decreased.
21a	Gas Supply Charge Summary	The Rider MFC has decreased.
21b	Pass-through Charge Summary	The "Universal Service Plan – Rider USP" has increased. The "Total Pass-through Charge" has increased for rate schedules RSS and RDS.
21c	Price-to-Compare Summary	The "Price-to-Compare" has decreased.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
26	Definitions - continued	Added a definition for "Maximum Daily Quantity". Renumbered definitions. Moved the definition for "Pipeline Scheduling Point" to page 27.
27	Definitions - continued	Added the existing definition of "Pipeline Scheduling Point" from page 26. Renumbered definitions. Revised the definition for "Residential Customer". Moved the definition for "Shipper" to page 28.
28	Definitions - continued	Added the existing definition of "Shipper" from page 27. Renumbered definitions. Moved the definition of "User Without Contract" to page 29.
29	Definitions - continued	Added the existing definition of "User Without Contract" from page 28.
32	Service Limitations - continued	Added a label of "2.3.3" to "Emergency Action Curtailments". Added "currently effective" before "Maximum Daily Quantity" in subparagraph "C.".
48	Extensions	Removed the word "dedicated" from the first paragraph of "8.2.1 Residential Distribution Service".
49	Extensions - continued	Revised subparagraph "(b)" of "Commercial and Industrial Distribution Service".
49a	Extensions - continued	New page. Added existing paragraph "8.2.3 Reduction or Elimination of Deposit" from page 50. Added new paragraph "8.2.4 Payment Period of Deposit". Added existing paragraph "8.2.4 Taxes on Deposits for Construction & Customer Advances" from page 50 and renumbered it as "8.2.5".
50	Extensions – continued	Moved existing paragraphs "8.2.3 Reduction or Elimination of Deposit" and "8.2.4 Taxes on Deposits for Construction & Customer Advances" to page 49a.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
97	Rate SDS – continued	Added the "Main Line Extension Deposit Installment Plan" paragraph.
100	Rate LGSS – continued	Added the "Main Line Extension Deposit Installment Plan" paragraph.
102	Rate LGSS – continued	Interstate pipeline name revision.
104	Rate LDS – continued	Added the "Main Line Extension Deposit Installment Plan" paragraph.
108	Rate MLSS – continued	Added the "Main Line Extension Deposit Installment Plan" paragraph.
109	Rate MLSS - continued	Interstate pipeline name revision.
110	Rate MLSS – continued	Interstate pipeline name revision.
112	Rate MLDS – continued	Added the "Main Line Extension Deposit Installment Plan" paragraph. Moved the "Minimum Charge" paragraph to page 113.
113	Rate MLDS – continued	Add existing "Minimum Charge" paragraph from page 112.
114	Rate MLDS – continued	Interstate pipeline name revision.
120	Rate NSS - continued	Interstate pipeline name revision.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
129	Rate NGV	Added the "Main Line Extension Deposit Installment Plan" paragraph.
147	Rider USP	Revised the "Annual Reconciliation" paragraph.
154	Rider PGC – continued	Interstate pipeline name revision.
156	Rider PGC – continued	Interstate pipeline name revision.
157	Rider PGC – continued	Interstate pipeline name revision.
161	Rider MFC	The MCF percentages have decreased.
165	Rider STAS	Removed the date of "January 1, 2014" in the first paragraph.
166	Rider EBS	Added "currently effective" before "Maximum Daily Quantity".
167	Rider EBS – continued	Revised "Option 1: Electing Service" paragraph.
168	Rider EBS – continued	Added "currently effective" before "MDQ" and "Maximum Daily Quantity". Removed repetitive text in last paragraph.
171	Rider EBS – continued	Removed references to "ninety percent (90%) of the Index".
183	RADS – Definitions (continued)	Moved definition "1.33 "month" to page 184.
184	RADS – Definitions (continued)	Added a definition for "Maximum Daily Quantity". Added "month" from page 183. Renumbered definitions. Moved the definition for "Natural Gas Supplier" to page 185.

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
185	RADS – Definitions (continued)	Added the existing definition for "Natural Gas Supplier" from page 184. Renumbered definitions. Moved definitions for "Primary FTS", "Reliability", "Retainage", "Rules and Regulations", "Security", and "Shipper" to page 185a.
185a	RADS – Definitions (continued)	New page. Added existing definitions for "Primary FTS", "Reliability", "Retainage", "Rules and Regulations", "Security", and "Shipper" from page 185. Added existing subparts "3.)" and "4.)" of the definition of "Shipper" from page 186. Added existing definitions of "Storage" and "Transmission" from page 186.
186	RADS	Moved subparts "3.)" and "4.)" of the definition of "Shipper" to page 185a. Moved definitions of "Storage" and "Transmission" to page 185a. Added existing "Initial NGS Application" paragraphs 2.3.3 and 2.3.4 from page 187.
187	RADS	Moved "Initial NGS Application" paragraphs 2.3.3 and 2.3.4 to page 186. Moved paragraph "2.4.3 Amount and Form of Security" and added criteria to page 187a.
187a	RADS	New page. Added existing subparagraph "2.4.3 Amount and Form of Security" from page 187. Added a list of legal and financial instruments that may be used as forms of security from 62.111(c) (2) of the PA Code.
188	RADS	Interstate pipeline name revision. Updated Index reference to match labeling in Platt's Inside FERC report.
200a	RADS	New page. Added interstate pipeline designation by pipeline scheduling point for identification of midpoint prices in Platts Gas Daily.
201	RADS	Added "currently effective" before "Maximum Daily Quantity". Revised presentation of Maximum Daily Quantity. Removed the text providing for a Maximum Daily Quantity in January for some types of customers. Added existing carry-over text from paragraph 3.2.4 from page 202.
202	RADS	Moved existing carry-over text from paragraph 3.2.4 to page 201. Added "currently effective" before "Maximum Daily Quantity".

LIST OF CHANGES MADE BY THIS TARIFF SUPPLEMENT

Page	Page Description	Revision Description
206	RADS	Added "currently effective" before "Maximum Daily Quantity". Revised presentation of Maximum Daily Quantity. Provided further detail with regard to "Standby Service".
207	RADS	Provided further detail with regard to "Standby Service". Revised the rate calculation for OFO charges. Moved paragraph 3.8.4 to page 207a.
207a	RADS	Added paragraph 3.8.4 from page 207.
208	RADS	Added "currently effective" before "Maximum Daily Quantity". Revised the rate calculation for OMO charges.
233	RADS	Interstate pipeline name revision. Revised paragraphs 4.7.4.1 and 4.7.4.3 to coincide with previously approved paragraph 4.7.4.2. Revised the reference to the index in Platt's Inside FERC's Gas Market Report.
235	RADS	Interstate pipeline name revision.
237	RADS	Interstate pipeline name revision.
239	RADS	Added a second paragraph under 4.9.5 Delivery Requirements.
241	RADS	Interstate pipeline name revision. Changed the upper case "C" in "Customers" to a lower case "c".
242	RADS	Interstate pipeline name revision. Changed the upper case "C" in "Customers" to a lower case "c". Revised the rate calculation for OFO charges.
243	RADS	Revised the rate calculation for Choice Under Delivery charges.
245	RADS	Revised subparagraph 4.13.3.2.1.
248	RADS	Removed "OMO" from subparagraph 4.16.1.

Table of Contents

(C) Indicates Change

Table of Contents (continued)

(C) Indicates Change

Table of Contents (continued)

(C) Indicates Change

Columbia Gas of Pennsylvania, Inc.

Rate Summary

Rate per thm

Residential Rate Schedules		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment		Pass-Through Charge 2/	State Tax Adjustment Surcharge 3/	Total Effective Rate
Rate RSS - Residential Sales Service								
Customer Charge	$	16.75	-	-		-	0.00	16.75
Usage Charge	$	0.55316	0.28465	(0.06811)		0.17745	0.00000	0.94715
Customer Transferring from Rate Schedule RDS - Usage Charge	$	0.55316	0.28465	-	4/	0.17745	0.00000	1.01526
Rate RDS - Residential Distribution Service								
Customer Charge	$	16.75	-	-			0.00	16.75
Usage Charge:								
Customers Electing CHOICE - 1st Year	$	0.55316	-	(0.06811)	5/	0.14652	0.00000	0.63157
Customers Electing CHOICE - 2nd Year	$	0.55316	-	-		0.14652	0.00000	0.69968

1/ Please see Page No. 21a for rate components.
2/ Please see Page No. 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
4/ If a customer transfers to RSS from RDS, the Gas Cost Adjustment shall not be billed for up to twelve billing cycles.
5/ If a customer transfers to RDS from RSS, the Gas Cost Adjustment shall be billed for up to twelve billing cycles.

Issued:

Effective:

Mark Kempic - President

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules <= 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Total Effective Rate
<u>Rate SGSS - Small General Sales Service</u>							
Customer Charge:							
Annual Throughput <= 6,440 thm	$	21.25	-	-	-	0.00	21.25
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00	-	-	-	0.00	48.00
Usage Charge							
Annual Throughput <= 6,440 thm	$	0.40870	0.28151	(0.06811) 4/	0.10461	0.00000	0.72671
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.36288	0.28151	(0.06811) 4/	0.10461	0.00000	0.68089
<u>Rate SCD - Small Commercial Distribution</u>							
Customer Charge:							
Annual Throughput <= 6,440 thm	$	21.25	-	-	-	0.00	21.25
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00	-	-	-	0.00	48.00
Usage Charge: Customers Electing CHOICE - 1st year							
Annual Throughput <=6,440 thm	$	0.40870	-	(0.06811) 5/	0.07368	0.00000	0.41427
Annual Throughput >6,440 and <=64,400 thm	$	0.36288	-	(0.06811) 5/	0.07368	0.00000	0.36845
Usage Charge: Customers Electing CHOICE - more than 1 year							
Annual Throughput <=6,440 thm	$	0.40870	-	-	0.07368	0.00000	0.48238
Annual Throughput >6,440 and <=64,400 thm	$	0.36288	-	-	0.07368	0.00000	0.43656
<u>Rate SGDS - Small General Distribution Service</u>							
Customer Charge:							
Annual Throughput <= 6,440 thm	$	21.25	-	-	-		21.25
Annual Throughput > 6,440 thm and <= 64,400 thm	$	48.00	-	-	-		48.00
Usage Charge - Priority One							
Annual Throughput <= 6,440 thm	$	0.39506	-	- 5/	0.10461	0.00000	0.49967 6/
Annual Throughput > 6,440 thm and <= 64,400 thm	$	0.34923	-	- 5/	0.10461	0.00000	0.45384 6/
Usage Charge - Non-Priority One							
Annual Throughput <= 6,440 thm	$	0.39506	-	- 5/	0.00010	-	0.39516 6/
Annual Throughput > 6,440 and <= 64,400 thm	$	0.34923	-	- 5/	0.00010	-	0.34933 6/

1/ Please see Page No. 21a for rate components.
2/ Please see Page No. 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
4/ If a customer transfers to SGSS from SCD or SGDS, the Gas Cost Adjustment shall not be billed for up to twelve billing cycles.
5/ If a customer transfers to SCD or SGDS from SGSS, the Gas Cost Adjustment shall be billed for up to twelve billing cycles.
6/ Plus Rider EBS Option 1 or 2 - See Page 21.

Columbia Gas of Pennsylvania, Inc.

Rate Summary

Rate per thm

Commercial / Industrial Rate Schedules > 64,400 therms - 12 Months Ending October		Distribution Charge	Gas Supply Charge 1/	Gas Cost Adjustment	Pass-through Charge 2/	State Tax Adjustment Surcharge 3/	Total Effective Rate
Rate LGSS - Large General Sales Service							
Customer Charge:							
Annual Throughput > 64,400 thm and <= 110,000 thm	$	229.75				0.00	229.75
Annual Throughput > 110,000 thm and <= 540,000 thm	$	757.34				0.00	757.34
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,947.06				0.00	1,947.06
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	3,028.76				0.00	3,028.76
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	5,841.18				0.00	5,841.18
Annual Throughput > 7,500,000 thm	$	8,653.60				0.00	8,653.60
Usage Charge:							
Annual Throughput > 64,400 thm and <= 110,000 thm	$	0.23050	0.28049	(0.06811) 4/	0.10451	0.00000	0.54739
Annual Throughput > 110,000 thm and <= 540,000 thm	$	0.21550	0.28049	(0.06811) 4/	0.10451	0.00000	0.53239
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.12999	0.28049	(0.06811) 4/	0.10451	0.00000	0.44688
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.11530	0.28049	(0.06811) 4/	0.10451	0.00000	0.43219
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.10347	0.28049	(0.06811) 4/	0.10451	0.00000	0.42036
Annual Throughput > 7,500,000 thm	$	0.06157	0.28049	(0.06811) 4/	0.10451	0.00000	0.37846
Rate SDS - Small Distribution Service							
Customer Charge:							
Annual Throughput > 64,400 thm and <= 110,000 thm	$	229.75	-	-	-	0.00	229.75
Annual Throughput > 110,000 thm and <= 540,000 thm	$	757.34	-	-	-	0.00	757.34
Usage Charge:							
Annual Throughput > 64,400 thm and <= 110,000 thm	$	0.23050	-	- 5/	-	0.00000	0.23050 6/
Annual Throughput > 110,000 thm and <= 540,000 thm	$	0.21550	-	- 5/	-	0.00000	0.21550 6/
Rate LDS - Large Distribution Service							
Customer Charge:							
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	1,947.06	-	-	-	0.00	1,947.06
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	3,028.76	-	-	-	0.00	3,028.76
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	5,841.18	-	-	-	0.00	5,841.18
Annual Throughput > 7,500,000 thm	$	8,653.60	-	-	-	0.00	8,653.60
Usage Charge:							
Annual Throughput > 540,000 thm and <= 1,074,000 thm	$	0.12999	-	- 5/	-	0.00000	0.12999 6/
Annual Throughput > 1,074,000 thm and <= 3,400,000 thm	$	0.11530	-	- 5/	-	0.00000	0.11530 6/
Annual Throughput > 3,400,000 thm and <= 7,500,000 thm	$	0.10347	-	- 5/	-	0.00000	0.10347 6/
Annual Throughput > 7,500,000 thm	$	0.06157	-	- 5/	-	0.00000	0.06157 6/

1/ Please see Page No. 21a for rate components.
2/ Please see Page No. 21b for rate components.
3/ The STAS percentage is reflected on Page No. 20 and is applied to the Customer Charge and the Distribution Charge.
4/ If a customer transfers to LGSS from SDS or LDS, the Gas Cost Adjustment shall not be billed for up to twelve billing cycles.
5/ If a customer transfers to SDS or LDS from LGSS, the Gas Cost Adjustment shall be billed for up to twelve billing cycles.
6/ Plus Rider EBS Option 1 or 2 - See Page 21.

Columbia Gas of Pennsylvania, Inc.

Other Rates Summary

Rate per thm

Description		Rate $/ thm		Applicable Rate Schedules
Price to Compare for Residential Gas Supply	$	0.24747	1/	RSS
Price to Compare for Commercial Gas Supply	$	0.24433	1/	SGSS (< = 64,400 thms)
State Tax Adjustment Surcharge Percentage		0.00000%		Customer and Distribution Charges on all rates
Rate SS - Standby Service	$	0.75310		Per therm based on a customer's Maximum Daily Firm Requirement. See Pages 134 - 136 herein for detail.

1/ Please see Page No. 21c for rate components.

Columbia Gas of Pennsylvania, Inc.

Rider Summary

Riders		Rate		Applicable Rate Schedules
Customer Choice - Rider CC	$	0.00010	/thm	RSS/RDS/SGSS/SGDS/SCD/DGDS
Universal Service Plan - Rider USP	$	0.07284	/thm	RSS/RDS
Distribution System Improvement Charge - Rider DSIC		0.00000%		This percentage is applied to a portion of the Distribution Charge and the Customer Charge. See Pages 177-180 for Rider DSIC details.
Elective Balancing Service - Rider EBS:				
Option 1 - Small Customer	$	0.01626	/thm	SGDS/SDS
Option 1 - Large Customer	$	0.00656	/thm	LDS/MLDS
Option 2 - Small Customer	$	0.00697	/thm	SGDS/SDS
Option 2 - Large Customer	$	0.00226	/thm	LDS/MLDS
Gas Procurement Charge - Rider GPC	$	0.00695	/thm	RSS/SGSS/LGSS/MLSS
Merchant Function Charge - Rider MFC	$	0.00416	/thm	RSS
Merchant Function Charge - Rider MFC	$	0.00102	/thm	SGSS
Purchased Gas Cost - Rider PGC		Pg. 21a & 21b		Rate Schedules specified on Page 21a & 21b

Columbia Gas of Pennsylvania, Inc.

Gas Supply Charge Summary

Rate per thm

Rate Schedule		PGCC	Rider GPC	Rider MFC	Total Gas Supply Charge
Rate CAP - Customer Assistance Plan	$	-	-	-	-
Rate RSS - Residential Sales Service	$	0.27354	0.00695	0.00416	0.28465
Rate SGSS - Small General Sales Service	$	0.27354	0.00695	0.00102	0.28151
Rate LGSS - Large General Sales Service	$	0.27354	0.00695	-	0.28049
Rate MLSS Main Line Sales Service	$	0.27354	0.00695	-	0.28049

Issued:

Effective:

Mark Kempic - President

Columbia Gas of Pennsylvania, Inc.

Pass-through Charge Summary
Rate per thm

Rate Schedule		PGDC	PGDC "E" Factor	Capacity Assignment Factor	Pipeline Refund	Rider CC	Rider USP	Total Pass-through Charge
Rate CAP - Customer Assistance Plan	$	0.11873	(0.01422)	(0.03093)	-	-	-	0.07358
Rate RSS - Residential Sales Service	$	0.11873	(0.01422)	-	-	0.00010	0.07284	0.17745
Rate SGSS - Small General Sales Service	$	0.11873	(0.01422)	-	-	0.00010	-	0.10461
Rate LGSS - Large General Sales Service	$	0.11873	(0.01422)	-	-	-	-	0.10451
Rate MLSS Main Line Sales Service	$	0.11873	(0.01422)	-	-	-	-	0.10451
Rate RDS - Residential Distribution Service	$	0.11873	(0.01422)	(0.03093)	-	0.00010	0.07284	0.14652
Rate SCD - Small Commercial Distribution (Choice)	$	0.11873	(0.01422)	(0.03093)	-	0.00010	-	0.07368
Rate SGDS - Small General Distribution Service								
Priority One (P1)	$	0.11873	(0.01422)	-	-	0.00010	-	0.10461
Non-Priority One (NP1)		-	-	-	-	0.00010	-	0.00010
Rate SDS - Small Distribution Service	$	-	-	-	-	-	-	-
Rate LDS - Large Distribution Service	$	-	-	-	-	-	-	-
Rate MLDS - Main Line Distribution Service	$	-	-	-	-	-	-	-

Issued:

Effective:

Mark Kempic - President

Columbia Gas of Pennsylvania, Inc.

Price-to-Compare (PTC) Summary
Rate per thm

Customer Class		PGCC	Gas Cost Adjustment	Capacity Assignment Factor	Rider GPC	Rider MFC	Total Price-to-Compare
Residential	$	0.27354	(0.06811)	0.03093	0.00695	0.00416	0.24747
Commercial < = 64,400 thm/year	$	0.27354	(0.06811)	0.03093	0.00695	0.00102	0.24433

Issued:

Effective:

Mark Kempic - President

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

1. The Gas Tariff - continued

1.6 Definitions - continued

29. Industrial Customer

    A customer using gas for creating or changing raw or unfinished material into another form or product through the application of heat or heat treating, steam agitation, evaporation, baking, drying, distilling, etc.

    Typical industrial users are manufacturing plants, machine shops, steel and iron mills, foundries, lumber planing and saw mills, canneries, dairies, meat packers, breweries, distilleries, potteries, railroad repair shops, refineries, creameries, flour mills, pump stations, ice plants, quarries, milk plants, mines, shipbuilders, chemical plants, grain elevators, food processing facilities, petrochemical operations in which the gas is the raw material, etc. If gas service is supplied through a single meter and is used for both industrial and commercial purposes, the service shall be considered industrial if the industrial usage is the predominant usage factor.

30. "Local Market Area" shall mean a continuous physically interconnected system of Company owned distribution piping through which the Company provides natural gas service to customers in a disrete geographic area, utilizing one or more common Points of Delivery from interstate pipeline supplier(s) or local gas supplier(s).

31. "Maximum Daily Quantity" or "MDQ" shall mean a Customer's maximum usage during a 24-hour period based on the most recent historical Customer consumption data. The Company will establish a winter MDQ for the November through March time period and a summer MDQ for the April through October time period. However, an adjustment may be made at any time upon agreement of the Customer and the Company. (C)

32. "Mcf" shall mean one thousand (1,000) cubic feet of gas.

33. "Month" shall mean calendar month.

34. "Medical Certificate" shall mean a written document, in a form approved by the Commission: 1) certifying that a customer or member of the customer's household is seriously ill or has been diagnosed with a medical condition which requires the continuation of service to treat the medical condition; and 2) signed by a licensed physician, nurse practitioner or physician's assistant.

35. "Pass-through Charge" shall mean the charge that appears as a line item on a residential, commercial and industrial bill for an account served pursuant to Rate Schedules CAP, RDS, RSS, SGSS, SCD, SGDS, LGSS, MLSS and PS. Pass-through Charges may include: 1) the Purchased Gas Demand Charge ("PGDC"); 2) the PGDC "E" Factor; 3) the Capacity Assignment Factor ("CAF"); 4) the Rider Customer Choice charge ("Rider CC"); and 5) the Rider Universal Service Plan charge ("Rider USP").

(C) Indicates Change

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

1. The Gas Tariff - continued

1.6 Definitions - continued

36. "Pipeline Scheduling Point" or "PSP" shall mean a single delivery point or set of delivery points grouped or designated by an upstream pipeline for purposes of scheduling gas supplies for delivery by such upstream pipeline and shall consist of the following: Interconnections with Dominion Transmission, Inc., Equitrans, L.P., National Fuel Gas Supply Corporation, Tennessee Gas Pipeline Company, Texas Eastern Transmission, LP and Columbia Gas Transmission, LLC. The (C) interconnections with Columbia Gas Transmission, LLC include the Market Areas and Master List of Interconnections as defined in the General Terms and Conditions of the FERC Gas Tariff of Columbia Gas Transmission, LLC. As of May 1, 2010, the Columbia Gas Transmission, LLC Pipeline Scheduling Points included: 25E-25 (Lancaster); 25-26 (Bedford); 25E-29 (Downingtown); 25-35 (Pittsburgh); 25-36 (Olean); 25-38 (Rimersburg); 25-39 (New Castle) and 25-40 (PA/WV Misc).

37. "Price-to-Compare" or "PTC" shall mean the dollar amount charged by the Company for gas supply and used by consumers to compare prices with other NGSs. The Price-to-Compare includes the PGCC, the CAF, the GPC, the MFC and the Gas Cost Adjustment.

38. Residential Customer

    A customer, at least 18 years of age, using gas in a single family residential dwelling or unit for space heating, air conditioning, cooking, water heating, incineration, refrigeration, laundry drying, lighting, incidental heating, or other domestic purposes. For residential utility service, the term "Customer" is further defined as a natural person in whose name a residential service account is listed and who is primarily responsible for payment of bills rendered for the service or any adult occupant whose name appears on the mortgage, deed or lease of the property for which the residential utility service is requested. A Customer whose service has been terminated or discontinued in compliance with this Tariff and existing Pennsylvania statute will remain a Customer if, within 30 days of discontinuance or termination, the Customer requests to have service reconnected or transferred to a new location.

    Included in this group are customers using gas through one meter set which provides service to (C) two or three dwelling units in a multi-family residence or building where the owner of the building occupies one of the dwelling units, or through one meter set to a combination of one dwelling unit and one or more business premises, where the residential premises is occupied by the owner of the building and is the predominant gas usage factor. If gas is supplied through a single meter and is used for both residential and commercial purposes, the service shall be considered residential if the residential usage is the predominant usage factor.

39. "Sales Service" shall mean service provided by the Company in which the customer purchases its gas supplies from the Company and the Company distributes the gas supplies to the Customer.

(C) Indicates Change

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

1. The Gas Tariff - continued

1.6 Definitions - continued

40. "Shipper" generally means the entity nominating gas service for Distribution Service accounts. Specifically, "Shipper" is defined as:

    i.) a General Distribution Service Customer that nominates gas for Distribution; or

    ii.) a Natural Gas Supplier that nominates the General Distribution Service Customer's gas for distribution, but which has not been appointed in writing as the Customer's agent by the Customer; or

    iii.) a Natural Gas Supplier that nominates General Distribution Service Customer's gas for distribution, which NGS is acting as the General Distribution Services Customer's duly authorized agent for the purpose of purchasing gas; or

    iv.) a Natural Gas Supplier that nominates the General Distribution Service Customer's gas for distribution, which NGS is acting as the General Distribution Service Customer's duly authorized aggregation agent for the purpose of purchasing gas.

41. "Supplier of Last Resort" shall mean the Company or another entity as determined pursuant to §2207 of the Act that provides natural gas supply services to customers that do not elect another supplier or choose to be served by the supplier of last resort, customers that are refused service from another natural gas supplier, or customers whose natural gas supplier fails to deliver the required gas supplies. Currently, the Company is the supplier of last resort for all customers under the terms of this tariff. Each customer may only have one supplier of last resort.

42. "Therm" or "thm" shall mean a unit of heat equivalent to 100,000 British thermal units. The Company uses thm as the unit of measure for billing its customers.

43. "Therm multiplier" shall mean a numeric multiplier that is applied to the volume of gas consumed (as measured in cubic feet, CCF, or MCF) to determine the amount of energy consumed (as measured in therms).

44. "Transmission Pipeline" shall mean pipelines and related facilities which are either: 1) owned by the Company in the form of a D-Line or a Company-owned pipeline that operates at a hoop stress of 20 percent or more of the specified minimum yield strength of the pipe as determined by 49 C.F.R §192.3; or 2) pipelines and related facilities owned by another company which obtains at least 90% of its gas operating revenues from the transportation of gas for others and classifies at least 90% of its mains (other than service pipe) as field and gathering lines, storage, or transmission lines. The Company's Customers are not typically served directly from a Transmission Pipeline, and according to the provisions set forth in the Termination of Service from Transmission Pipelines section of this Tariff, the Company reserves the right to remove, relocate or abandon its Transmission Pipelines.

(C) Indicates Change

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

1. The Gas Tariff - continued

1.6 Definitions - continued

45. "User Without Contract" shall mean any person who has not contacted the Company to establish service in their name but who is receiving the benefits of natural gas service. This situation includes, but is not limited to, situations wherein the Company arrives at the premise to disconnect the service as a result of a request from the previous customer and finds the premise occupied. User Without Contract does not include instances where the Company's meter or equipment has been tampered with; the service was obtained through fraud or material misrepresentation of the customer's identity; a tariff provision was violated so as to endanger the safety of a person or the integrity of the Company's system, or the gas service was otherwise established without the Company's authorization.

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

2. Service Limitations - continued

2.3 Gas Emergency Rules - continued

2.3.3 Emergency Actions Curtailments (C)

A. In the event of an Emergency, if, in the sole judgment of the Company, there is sufficient time, the Company shall use reasonable business and operational efforts to: interrupt all interruptible services, issue Operational Flow and Matching Orders and Operational Alerts pursuant to the Rules Applicable to Distribution Service section of this tariff, and call for voluntary usage reductions by all customers prior to requiring reductions in gas consumption according to the provisions below.

B. In the event of an Emergency, the Company may curtail, in part or in whole, natural gas supply and/or distribution service for each commercial and industrial customer that is not a Priority 1 customer. Such curtailments will be made without regard to priorities of use as necessary to minimize the potential threat to public health and safety. Emergency Action curtailments will not require reductions to a level below the amount necessary for Plant Protection Use as defined in the Priority-Based Curtailment Definitions section. When all other service has been curtailed except for Priority 1 service and the Company continues to be unable to meet Priority 1 requirements, the Company shall exercise its judgment as to any further curtailment that may be necessary and shall utilize measures designed to minimize harm to customers if curtailments to plant protection use are found to be necessary. The Company shall restore service as soon as practicable to any gas-fired electric generation facility that is deemed critical to electric system reliability by the electrical system's control area operator.

C. In order to implement Emergency Action Curtailments, the Company shall provide an authorized usage factor using the means most likely to reach impacted customers (via telephone, fax, e-mail, electronic bulletin board or other reasonable means). For industrial and commercial customers taking General Distribution Service, the authorized usage factor will be based on each customer's then currently effective Maximum Daily Quantity. For sales (C) service customers, the Company will base the authorized usage factor upon a recent billing cycle or other readily available consumption data that is available to both the customer and the Company.

D. Emergency Action Curtailments shall be for a period specified by the Company until further notice, but shall last no more than five business days unless extended by Commission order. As an alternative to extending mandatory reductions for periods beyond five days, the Commission may order the Company to initiate Priority-Based Curtailments as defined below. The Company may change a customer's authorized usage factor, upon notice, at any time during an Emergency.

(C) Indicates Change

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

8. Extensions

8.1 Service Connections

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 (C) 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

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

8. Extensions - Continued

8.2 Capital Expenditure Policy – Continued

8.2.2 Commercial and Industrial Distribution Service

The applicants will be required to provide a refundable cash deposit to the Company equal to the difference between the minimum capital investment required to serve the applicant's gas requirements and the amount of capital that the Company can justify investing in the project, based on the anticipated gas requirements of the applicant(s). Minimum capital investment is the capital expenditure required to serve only the gas requirements requested by the particular applicant(s).

(a) Projects Where the Net Present Value of the Cash Flows, Using the Minimum Capital Investment, is Equal to or Greater than Zero.

Such projects are economically feasible provided that there are assurances that the applicant will use the projected quantities of gas for the minimum time period stated in the agreement. Such assurances may be provided in the form of a minimum use agreement, in which applicant contractually agrees to take delivery of certain minimum quantities of gas, and to pay the applicable distribution charges for such quantities, irrespective of applicant's actual consumption of gas. At the Company's sole discretion, a deposit may be required if the Company is not certain that the applicant will use the quantity of gas, as projected, for the entire Minimum Time Period. The maximum required deposit shall be no more than the minimum capital investment.

(b) Projects Where the Net Present Value of the Cash Flows, Using the Minimum Capital Investment, is Less than Zero.

The Company shall require a refundable deposit in the amount equal to the net present value when the net present value is less than zero. For example, if the net present value of a project is -$1,000, the Company shall require a $1,000 refundable deposit. In addition, if there is uncertainty that the applicant will use the projected quantity of gas for the minimum time period stated in the agreement, the Company may, in its sole discretion, (1) require the Applicant to pay an additional refundable deposit, or (2) require the applicant to enter into a minimum use agreement, in which applicant contractually agrees to take delivery of certain minimum quantities of gas, and to pay the applicable distribution charges for such quantity, irrespective of applicant's actual consumption of gas. The additional refundable deposit, if required, shall be no more than the combined total of the Company's minimum capital investment and the net present value. For example, if the Company's minimum capital investment is $10,000 and the net present value of the project is -$1,000, the applicant shall be required to provide an additional $9,000 deposit. (C)

For purposes of subsection (a) and (b), above, 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 quantity, rate schedule, cost of gas, operating and maintenance expense, interest and taxes.

(C) Indicates Change

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

8. Extensions – Continued

8.2 Capital Expenditure Policy – Continued

8.2.3 Reduction or Elimination of Deposit

In any case where a deposit is required, it may be reduced or eliminated, if in the Company's judgment, the institution of such service will benefit other customers within a reasonable period of time.

8.2.4 Payment Period of Deposit (C)

When an applicant's projected annual usage is greater than 64,400 therms, the Company and the applicant may negotiate the period over which the deposit will be paid. If the applicant pays thirty percent (30%) of the deposit prior to commencement of the line extension construction, the remaining balance of the deposit may be paid over a period that is agreed upon between the Company and the applicant. Otherwise, the payment period will not exceed ten (10) years. The terms of any payment period will be memorialized in an agreement between the applicant and the Company. The installment amount will be added to and included in the Customer Charge line item on the customer's bill.

8.2.5 Taxes on Deposits for Construction & Customer Advances

Any deposit, advance or other like amounts received from the applicant which shall constitute taxable income as defined by the Internal Revenue Service will have the income taxes segregated in a deferred account for inclusion in rate base in a future rate case proceeding. Such income taxes associated with a deposit or advance will not be charged to the specific depositor of the capital.

(C) Indicates Change

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

8. Extensions - continued

8.3 Deposits and Refunds

When a deposit is required by the Company, the terms and conditions of the project and the refund will be specified in an agreement between the Company and the applicant.

Part or all of the deposit may be subject to refund to the applicant upon such basis or conditions as may be mutually agreeable to the Company and the applicant.

8.4 Ownership and Maintenance

The Company shall own, maintain and renew, when necessary, its main extension and/or service line from its main to the point of delivery, as defined in Rule 7.1.

8.5 Interference with Facilities

The Company's main, service line, curb valve shall not be opened, tampered or interfered with at any time. Any action taken, without the Company's prior knowledge, will be considered an action endangering the safety of a person or the integrity of the Company's delivery system and will be grounds for immediate termination of service.

8.6 Special Facilities

Any special services, facilities, instrumentalities or non-standard construction methodologies which may be rendered or furnished by the Company for an applicant or customer at his request or at the direction of a governmental authority, and not provided for in the Company's rate schedules, and not ordinarily, necessarily, or directly involved in the furnishing of natural gas distribution service, including but not limited to any distribution system improvements necessary to serve customers seeking to add gas fired generating units, natural gas vehicle filling stations or other customer equipment that places higher than typical demands on the distribution system, shall be paid for by the applicant or customer for whom such services, facilities, instrumentalities or non-standard construction methodologies are furnished, and such costs shall be in addition to the charges for natural gas distribution service provided for in the applicable rate schedule or in addition to any deposit required under this section.

(C) Indicates Change

RATE SDS - SMALL DISTRIBUTION SERVICE (Continued)

RATE

The customers under this rate schedule shall be subject to a Customer Charge and a Distribution Charge.

The rate information is detailed in the Rate Summary pages of this Tariff.

The Customer Charge will be determined based upon the customer's actual throughput quantities, including sales and distribution, measured in therms (thm), for the twelve most recent billing cycle periods ending with the October billing cycle. If a customer does not have sufficient consumption history to determine its Customer Charge based on twelve months, the Customer Charge will be developed by annualizing the consumption history available. In the instance where a customer has no consumption history, the Company will request the customer to submit estimated annual gas requirements, including sales and distribution, upon which to develop the Customer Charge. The Company in all cases retains the right to review and modify the customer's estimate where necessary. A customer's Customer Charge will remain constant annually, subject to change as of the January billing cycle of each year.

In all cases, the Company reserves the right to review the Customer Charge and, upon receipt of satisfactory proof, to adjust the Customer Charge to reflect the installation and use of energy efficient gas burning equipment, or the implementation of energy conservation practices or measures, which results in a measurable permanent change in the customer's requirement or consumption.

The Distribution Charge may be flexed in accordance with the Flexible Rate Provisions set forth in the Rules and Regulations of this Tariff.

MAIN LINE EXTENSION DEPOSIT INSTALLMENT PLAN (C)

Applicants eligible for Rate Schedule SDS who have entered into an agreement with the Company to make payments for a main line extension pursuant to the Payment Period of Deposit paragraph in the Capital Expenditure Policy section of Rule 8. Extensions of these Rules and Regulations Governing the Distribution and Sale of Gas, will have the installment amount included in the cyclical bill for service issued by the Company. The installment amount will be added to the Customer Charge for the duration of the installment payment plan.

MINIMUM CHARGE

The minimum charge shall be the sum of (a) the Customer Charge; plus (b) purchased gas demand charges, if any, under Rate SS. In the event of curtailment in the delivery of gas by the Company below the Maximum Daily Firm Requirement of the customer, if any, under Rate SS, or complete or partial suspension of operation by the customer due to strikes, fires, floods, explosions or other similar casualties, the Customer Charge shall be reduced in direct proportion to the ratio which the number of days of curtailed service or complete or partial suspension of operation bears to the number of days in the billing period.

STATE TAX ADJUSTMENT SURCHARGE

The above charges are subject to a State Tax Adjustment Surcharge as set forth in the tariff.

ELECTIVE BALANCING SERVICES RIDER

Distribution service under this rate schedule shall be subject to the provisions of Rider EBS as set forth within this Tariff.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

Rate SDS is subject to a Distribution System Improvement Charge as specified within Rider DSIC of this Tariff.

(C) Indicates Change

RATE LGSS - LARGE GENERAL SALES SERVICE

APPLICABILITY

Throughout the territory served under this Tariff.

AVAILABILITY

Available at one location, for the total requirements of any commercial or industrial customer whose purchase requirements are in excess of 64,400 thm, and who does not contract for distribution service.

Customers who take service under this rate schedule are entitled to firm retail gas service from the Company.

RATE

The customers under this rate schedule shall be subject to a Customer Charge, a Gas Supply Charge, a Distribution Charge, a Gas Cost Adjustment and a Pass-through Charge.

The rate information is detailed in the Rate Summary pages of this Tariff.

DETERMINATION OF CUSTOMER CHARGE

The Customer Charge will be determined based upon the customer's actual throughput quantities, including sales and distribution if the customer previously contracted for distribution service, measured in therms (thm), for the twelve most recent billing cycles ending with the October billing cycle. If a customer does not have sufficient consumption history to determine its Customer Charge based on twelve months, the Customer Charge will be developed by annualizing the consumption history available. In the instance where a customer has no consumption history, the Company will request the customer to submit estimated annual gas requirements upon which to develop the Customer Charge. The Company, in all cases, retains the right to review and modify the customer's estimate where necessary. A customer's Customer Charge will remain constant annually, subject to change as of the January billing of each year.

In all cases, the Company reserves the right to review the customer's Customer Charge, and upon receipt of satisfactory proof, to adjust the Customer Charge to reflect the installation and use of energy efficient gas burning equipment, or the implementation of energy conservation practices or measures, which result in a measurable permanent change in the customer's requirements or consumption.

MAIN LINE EXTENSION DEPOSIT INSTALLMENT PLAN (C)

Applicants eligible for Rate Schedule LGSS who have entered into an agreement with the Company to make payments for a main line extension pursuant to the Payment Period of Deposit paragraph in the Capital Expenditure Policy section of Rule 8. Extensions of these Rules and Regulations Governing the Distribution and Sale of Gas, will have the installment amount included in the cyclical bill for service issued by the Company. The installment amount will be added to the Customer Charge for the duration of the installment payment plan.

(C) Indicates Change

RATE LGSS - LARGE GENERAL SALES SERVICE (Continued)

SPECIAL PROVISIONS

1. The term of service shall be for a one (1) year period beginning November 1 of each year. Service hereunder shall be automatically renewed each year unless notice to discontinue service is given by the customer not less than sixty (60) days prior to November 1. Service commencing hereunder subsequent to the November billing cycle of any year shall be for the remainder of the twelve-month period ending with the October billing cycle and then placed on an annual basis.

2. New customers, customers transferring to or from this rate schedule shall be permitted to take service under this Rate Schedule only if: (1) the Company can obtain any increase in its pipeline capacity with Columbia Gas Transmission, LLC under the FTS rate schedule or any successor rate schedule that is required to accommodate such transfer; or (2) the Company, in its sole judgment, concludes that no increase in the Company's pipeline capacity under Columbia Gas Transmission, LLC FTS rate schedule or any successor rate schedule is required. The Company shall establish the date any transfer is to be effective. (C)

3. Energy usage eligibility for this rate schedule shall be determined annually. In the event Customer's annual purchases are less than or equal to 64,400 thm, the customer shall be transferred to Rate SGSS.

RULES AND REGULATIONS

The Rules and Regulations Governing the Distribution and Sale of Gas of this Tariff, which are not inconsistent with the provisions of this rate schedule, shall govern, where applicable, the supply of gas service under this rate schedule.

(C) Indicates Change

RATE LDS - LARGE DISTRIBUTION SERVICE (Continued)

RATE

The customers under this rate schedule shall be subject to a Customer Charge, and a Distribution Charge.

The rate information is detailed in the Rate Summary pages of this Tariff.

The Customer Charge will be determined based upon the Customer's actual throughput quantities, including sales and distribution, measured in therms (thm), for the twelve most recent billing cycles ending with the October billing cycle. If a Customer does not have sufficient consumption history to determine its Customer Charge based on twelve months, the Customer Charge will be developed by annualizing the consumption history available. In the instance where a customer has no consumption history, the Company will request the Customer to submit estimated annual gas requirements, including sales and distribution, upon which to develop the Customer Charge. The Company in all cases retains the right to review and modify the Customer's estimate where necessary. A customer's Customer Charge will remain constant annually, subject to change with the January billing cycle of each year.

In all cases, the Company reserves the right to review the Customer Charge and, upon receipt of satisfactory proof, to adjust the Customer Charge to reflect the installation and use of energy efficient gas burning equipment, or the implementation of energy conservation practices or measures, which results in a measurable permanent change in the customer's requirement or consumption.

The applicable Distribution Charge for all distribution quantities shall be determined based upon the Customer Charge group in which the Customer is placed, as established annually above.

The Distribution Charge may be flexed in accordance with the Flexible Rate Provisions set forth in the Rules and Regulations of this Tariff.

MAIN LINE EXTENSION DEPOSIT INSTALLMENT PLAN (C)

Applicants eligible for Rate Schedule LDS who have entered into an agreement with the Company to make payments for a main line extension pursuant to the Payment Period of Deposit paragraph in the Capital Expenditure Policy section of Rule 8. Extensions of these Rules and Regulations Governing the Distribution and Sale of Gas, will have the installment amount included in the cyclical bill for service issued by the Company. The installment amount will be added to the Customer Charge for the duration of the installment payment plan.

(C) Indicates Change

RATE MLSS – MAIN LINE SALES SERVICE (Continued)

DETERMINATION OF CUSTOMER CHARGE

The Customer Charge will be determined based upon the customer's actual throughput quantities, including sales and distribution if the customer previously contracted for distribution service, measured in therms (thm), for the twelve most recent billing cycles ending with the October billing cycle. If a customer does not have sufficient consumption history to determine its Customer Charge based on twelve months, the Customer Charge will be developed by annualizing the consumption history available. In the instance where a customer has no consumption history, the Company will request the customer to submit estimated annual gas requirements, upon which to develop the Customer Charge. The Company in all cases retains the right to review and modify the customer's estimate where necessary. A customer's Customer Charge will remain constant annually, subject to change as of the January billing cycle of each year.

In all cases, the Company reserves the right to review the Customer Charge and, upon receipt of satisfactory proof, to adjust the Customer Charge to reflect the installation and use of energy efficient gas burning equipment, or the implementation of energy conservation practices or measures, which results in a measurable permanent change in the customer's requirement or consumption.

MAIN LINE EXTENSION DEPOSIT INSTALLMENT PLAN (C)

Applicants eligible for Rate Schedule MLSS who have entered into an agreement with the Company to make payments for a main line extension pursuant to the Payment Period of Deposit paragraph in the Capital Expenditure Policy section of Rule 8. Extensions of these Rules and Regulations Governing the Distribution and Sale of Gas, will have the installment amount included in the cyclical bill for service issued by the Company. The installment amount will be added to the Customer Charge for the duration of the installment payment plan.

MINIMUM CHARGE

The minimum charge shall be the Customer Charge. In the event of curtailment in the delivery of gas by the Company or complete or partial suspension of operation by the customer due to strikes, fires, floods, explosions or other similar casualties, the Customer Charge shall be reduced in direct proportion to the ratio which the number of days of curtailed service or complete or partial suspension of operation bears to the number of days in the billing period.

STATE TAX ADJUSTMENT SURCHARGE

The charges described in this rate schedule are subject to a State Tax Adjustment Surcharge as set forth in the tariff.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

Rate MLSS is subject to a Distribution System Improvement Charge as specified within Rider DSIC of this Tariff.

(C) Indicates Change

RATE MLSS – MAIN LINE SALES SERVICE (Continued)

RIDER PGC

The Pass-through Charge and Gas Supply Charge in this rate schedule include recovery of purchased gas costs pursuant to the Purchased Gas Cost Rider as set forth in this Tariff.

TERMS OF PAYMENT

Bills for sales service will be rendered monthly and are due and payable upon presentation. All bills shall be paid on or before the final date of payment shown on the bill, which date shall not be less than fifteen (15) days after presentation (date of postmark).

If the customer fails to pay the full amount of any bill, a delayed payment penalty charge of one and one-quarter percent (1 1/4%) per billing cycle shall accrue on the portion of the bill that is unpaid on the due date.

SPECIAL PROVISIONS APPLICABLE TO ALL MLSS CUSTOMERS

1. Customers desiring to transfer to or from this rate schedule must notify the Company in writing. Transfers to or from this rate schedule will be allowed only if: (1) the Company can obtain any increase or decrease in its gas supplies, pipeline capacity and storage capacity, or any combination thereof that is required to accommodate such change; or (2) the Company, in its sole judgment, concludes that no increase or decrease is required. The Company shall establish the date any transfer is to be effective.
2. The Company reserves the right, as a condition of service under this Rate Schedule, to require any customer requesting service under this rate schedule to install and bear the costs associated with a daily demand reading meter and such installation shall be at the expense of the customer, excluding the cost of the meter plus all costs associated with dedicated telephone lines and telemetering equipment. The Company also reserves the right to require installation of such a meter, at the customer's expense, as a condition of continuation of service under this Rate Schedule. The meter and associated telemetering equipment shall be the property of the Company.
3. Energy usage eligibility for this rate schedule shall be determined annually. In the event Customer's annual purchases are less than or equal to 274,000 thm, the customer shall be transferred to either Rate LGSS or Rate SGSS effective the immediately succeeding January billing cycle.
4. New customers and customers transferring to or from this Rate Schedule shall be permitted to take service under this Rate Schedule only if: (1) the Company can obtain any increase in its pipeline capacity with Columbia Gas Transmission, LLC under the FTS rate schedule or any successor rate schedule that is required to accommodate such transfer; or (2) the Company, in its sole judgment, concludes that no increase in the Company's pipeline capacity under Columbia Gas Transmission, LLC FTS rate schedule or any successor rate schedule is required. The Company shall establish the date any transfer is to be effective. (C)

(C) Indicates Change

RATE MLSS - MAIN LINE SALES SERVICE (Continued)

SPECIAL PROVISION APPLICABLE TO CLASS I MLSS CUSTOMERS

In the event a Class I MLSS customer desires to obtain firm transportation capacity on the interstate pipeline system of Columbia Gas Transmission, LLC, as to which supplier the Company may exercise an option to (C) convert daily firm wholesale entitlement to daily firm transportation capacity entitlement under Federal Energy Regulatory Commission (FERC) approved rate schedules pursuant to Order 500 and successor orders of that Agency, the Company may assign daily firm transportation capacity entitlement to a Class I MLS customer under the following conditions:

(a) If, in the exercise of its informed business judgment, the Company determines that it can exercise its conversion option under FERC Order 500 and/or assign such increased transportation capacity without impairing its ability to meet its public service obligation to all customers and its ability to pursue a least cost acquisition policy to obtain system supplies. The Company reserves the right to limit any such conversion and/or assignment as necessary to maintain its ability in this regard;

(b) The Class I MLSS customer agrees to maintain the customer's existing contractual Maximum Daily Firm Requirement under Rate SS - Standby Service (if any) during the term of the assignment;

(c) The Class I MLSS customer signs an agreement committing to pay for the firm transportation demand charges constituting the Company as its agent to purchase gas to be redelivered to the Class I MLSS customer after firm transportation service has been provided using the assigned capacity;

(d) The term of this assignment shall be coextensive with the term of the agency agreement, subject to renewal with express approval of the Public Utility Commission;

(e) This provision shall be operative only so long as the Company continues to have the option to (C) convert daily firm wholesale entitlement to daily firm transportation capacity requirements under FERC Order 500 or any successor thereto.

RULES AND REGULATIONS

The Rules and Regulations Governing the Distribution and Sale of Gas of this Tariff, which are not inconsistent with the provisions of this rate schedule, shall govern, where applicable, the supply of distribution service under this rate schedule.

(C) Indicates Change

RATE MLDS – MAIN LINE DISTRIBUTION SERVICE (Continued)

RATE

The customers under this rate schedule shall be subject to a Customer Charge, and a Distribution Charge.

The rate information is detailed in the Rate Summary pages of this Tariff.

The applicable Distribution Charge for all distribution quantities for MLDS Class II customers shall be determined based upon the Customer Charge group in which the Customer is placed, as established annually.

The Distribution Charge may be flexed in accordance with the Flexible Rate Provisions set forth in the Rules and Regulations of this Tariff.

STATE TAX ADJUSTMENT SURCHARGE

The charges described in this rate schedule are subject to a State Tax Adjustment Surcharge as set forth in the Tariff.

ELECTIVE BALANCING SERVICES RIDER

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

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE

Rate MLDS is subject to a Distribution System Improvement Charge as specified within Rider DSIC of this Tariff.

DETERMINATION OF CUSTOMER CHARGE

The Customer Charge will be determined based upon the customer's actual throughput quantities, including sales and distribution, measured in therms (thm), for the twelve most recent billing cycle periods ending with the October billing cycle. If a customer does not have sufficient consumption history to determine its Customer Charge based on twelve months, the Customer Charge will be developed by annualizing the consumption history available. In the instance where a customer has no consumption history, the Company will request the customer to submit estimated annual gas requirements, including sales and distribution, upon which to develop the Customer Charge. The Company in all cases retains the right to review and modify the customer's estimate where necessary. A customer's Customer Charge will remain constant annually, subject to change with the January billing cycle each year.

In all cases, the Company reserves the right to review the Customer Charge and, upon receipt of satisfactory proof, to adjust the Customer Charge to reflect the installation and use of energy efficient gas burning equipment, or the implementation of energy conservation practices or measures, which results in a measurable permanent change in the customer's requirement or consumption.

MAIN LINE EXTENSION DEPOSIT INSTALLMENT PLAN (C)

Applicants eligible for Rate Schedule MLDS who have entered into an agreement with the Company to make payments for a main line extension pursuant to the Payment Period of Deposit paragraph in the Capital Expenditure Policy section of Rule 8. Extensions of these Rules and Regulations Governing the Distribution and Sale of Gas, will have the installment amount included in the cyclical bill for service issued by the Company. The installment amount will be added to the Customer Charge for the duration of the installment payment plan.

(C) Indicates Change

RATE MLDS – MAIN LINE DISTRIBUTION SERVICE (Continued)

MINIMUM CHARGE

The minimum charge shall be the sum of (a) the Customer Charge; plus (b) purchased gas demand charges, if any, under Rate SS. In the event of curtailment in the delivery of gas by the Company below the Maximum Daily Firm Requirement of the Customer, if any, under Rate SS, or complete or partial suspension of operation by the customer due to strikes, fires, floods, explosions or other similar casualties, the Customer Charge shall be reduced in direct proportion to the ratio which the number of days of curtailed service or complete or partial suspension of operation bears to the number of days in the billing period.

APPLICABLE SALES SERVICE RATE

Customers under this Rate Schedule desiring to purchase gas shall be charged an amount for recovery of purchased gas costs as set forth in the Rules Applicable to Distribution Service, plus the non-gas portion of distribution charges contained in the first block of Rate SGDS – Small General Distribution Service.

Provided, however, that sales service hereunder shall be considered imbalance gas as defined in the Consumption in Excess of Deliveries section in Paragraph 3 of the Rules Applicable to Distribution Service. The Company undertakes no responsibility to obtain sufficient gas supplies to avoid interruption of sales service on a daily basis, and service is totally interruptible on any day when the Company gives notice to the customer that gas supply is inadequate to supply the customer's requirements, except to the extent the customer nominates Maximum Daily Firm Requirement under Rate SS.

The Company shall give the customer 2 hours advance notice of interruption. Customer agrees that Company shall not be liable for any loss or damage that may be sustained by the customer by reason of any interruption of service.

On any day when the Customer has been given notice by the Company to interrupt, any quantity of gas taken in excess of the quantity specified to be made available that day shall constitute unauthorized takes and shall be subject to the charges set forth in the Rules Applicable to Distribution Service. Payment of such penalty charge shall be in addition to the charges specified above.

TERMS OF PAYMENT

Gas distributed hereunder shall be billed in accordance with the terms and conditions set forth in the customer's executed contract governing distribution service. Bills for distribution service will be rendered monthly and are due and payable upon presentation. All bills shall be paid on or before the final date of payment shown on the bill, which date shall not be less than fifteen (15) days after presentation (date of postmark).

If the customer fails to pay the full amount of any bill, a delayed payment charge of one and one-quarter percent (1 1/4%) per billing cycle shall accrue on the portion of the bill that is unpaid on the due date.

SPECIAL PROVISIONS APPLICABLE TO ALL MLDS CUSTOMERS

1. Within sixty (60) days of receipt of all necessary information requested by the Company, to evaluate a customer's application, the Company will respond to the application and agree either to supply service or to deny service on the grounds of insufficient capacity. If the Company refuses to provide distribution service under this rate schedule, the Company shall provide detailed support for its decision.

2. Customers desiring to transfer to or from this rate schedule must notify the Company in writing. Transfers to or from this rate schedule will be allowed only if: (1) the Company can obtain any increase or decrease in its gas supplies, transportation capacity and storage capacity, or any combination thereof that is required to accommodate such change; or (2) the Company, in its sole judgment, concludes that no increase or decrease is required. The Company shall establish the date any transfer is to be effective.

(C) Indicates Change

RATE MLDS - MAIN LINE DISTRIBUTION SERVICE (Continued)

SPECIAL PROVISIONS APPLICABLE TO ALL MLDS CUSTOMERS – Continued

3. Customers that request to be transferred to this rate schedule prior to the end of the Customer's existing contract under another rate schedule shall be required to contract for Maximum Daily Firm Requirement under Rate SS at the level of the Customer's Maximum Daily Firm Requirement, if any, under such existing contract.
4. The Company reserves the right, as a condition of service under this Rate Schedule, to require any customer requesting service under this rate schedule to install and bear the costs associated with a daily demand reading meter and such installation shall be at the expense of the customer, excluding the cost of the meter plus all costs associated with dedicated telephone lines and telemetering equipment. The Company also reserves the right to require installation of such a meter, at the customer's expense, as a condition of continuation of service under this Rate Schedule. The meter and associated telemetering equipment shall be the property of the Company.
5. Energy usage eligibility for this rate schedule shall be determined annually. In the event Customer's annual throughput is less than or equal to 274,000 thm, the customer shall be transferred to either Rate LDS, Rate SDS or Rate SGDS effective the immediately succeeding January billing cycle.

SPECIAL PROVISION APPLICABLE TO CLASS I MLDS CUSTOMERS

In the event a Class I MLS customer desires to obtain firm transportation capacity on the interstate pipeline system of Columbia Gas Transmission, LLC as to which supplier the Company may exercise an option to (C) convert daily firm wholesale entitlement to daily firm transportation capacity entitlement under Federal Energy Regulatory Commission (FERC) approved rate schedules pursuant to Order 500 and successor orders of that Agency, the Company may assign daily firm transportation capacity entitlement to a Class I MLS customer under the following conditions:

(a) If, in the exercise of its informed business judgment, the Company determines that it can exercise its conversion option under FERC Order 500 and/or assign such increased transportation capacity without impairing its ability to meet its public service obligation to all customers and its ability to pursue a least cost acquisition policy to obtain system supplies. The Company reserves the right to limit any such conversion and/or assignment as necessary to maintain its ability in this regard;
(b) The Class I MLS customer agrees to maintain the customer's existing contractual Maximum Daily Firm Requirement under Rate SS - Standby Service (if any) during the term of the assignment;
(c) The Class I MLS customer signs an agreement committing to pay for the firm transportation demand charges constituting the Company as its agent to purchase gas to be redelivered to the Class I MLS customer after firm transportation service has been provided using the assigned capacity;
(d) The term of this assignment shall be coextensive with the term of the agency agreement, subject to renewal with express approval of the Public Utility Commission;
(e) This provision shall be operative only so long as Columbia continues to have the option to convert daily firm wholesale entitlement to daily firm transportation capacity requirements under FERC Order 500 or any successor thereto.

RULES AND REGULATIONS

The Rules and Regulations Governing the Distribution and Sale of Gas of this Tariff, which are not inconsistent with the provisions of this rate schedule, shall govern, where applicable, the supply of distribution service under this rate schedule.

(C) Indicates Change

RATE NSS - NEGOTIATED SALES SERVICE (Continued)

CREDITS TO THE PURCHASED GAS COST RIDER

The Company shall credit as revenues for recovery of purchased gas costs, an amount equal to (1) the Rider EBS-Option 2 rates and (2) interstate pipeline capacity costs. The amount of the credit for interstate pipeline capacity costs shall be separately computed for each NSS contract and shall be equal to the greater of the following:

a. Actual sales multiplied by the average rate per thm of all final accepted bids for thirty day recallable capacity received by Columbia five days prior to the commencement of each month of the contract; or

b. Actual sales multiplied by $.00465/thm in December, January and February; and $.00093/thm in all other months.

For firm service not provided by Rate SS-Standby Service, the Company shall credit an additional amount for recovery of interstate pipeline capacity costs. The amount of the credit shall be separately computed for each firm NSS contract and shall be equal to the actual capacity costs incurred to acquire additional capacity, which was obtained, on either a short-term or long-term basis, in order to provide firm service to the customer on days when service otherwise would be interrupted.

For firm service provided by Rate SS-Standby Service, the credit for recovery of interstate pipeline capacity costs shall be computed in accordance with Rate SS.

SPECIAL PROVISIONS

1. The distribution non-gas margin component of sales under this rate schedule shall be no less than the otherwise-applicable distribution rate offered by Columbia to the customer.

2. Subject to the minimum pricing provisions set forth herein, the price and length of term for service under this rate schedule shall be established through negotiations between the Company and the customer. Provided, however, that no contract shall be entered into hereunder without the Company first posting, on Columbia Gas Transmission, LLC's Electronic (C)
Bulletin Board, thirty day recallable capacity.

3. If in any billing cycle the actual usage by the NSS customer is less than nominated quantities, the nominated quantities must be paid for by the customer and the quantity not taken will be subject to the provisions of Rider EBS.

4. The Company shall schedule gas purchases sufficient to meet quantities nominated under this rate schedule each month.

5. On any day when a Customer electing interruptible service under this rate schedule has been given notice by the Company to interrupt, any quantity of gas taken in excess of the quantity specified to be made available that day shall constitute consumption in excess of deliveries and shall be subject to provisions of the Consumption in Excess of Deliveries section in Rule 3 of the RADS. Payment of the charges specified in the above mentioned paragraph shall be in (C)
addition to the charges specified in this rate schedule.

(C) Indicates Change

RATE NGV - NATURAL GAS VEHICLE SERVICE

APPLICABILITY

Throughout the territory served under this Tariff.

AVAILABILITY

Available to any Customer for use of natural gas directly in a natural gas vehicle ("NGV"). The following shall qualify as a customer for purposes of this rate schedule:

1. The operator of a public fueling station.
2. The owner/operator of a natural gas vehicle or fleet of vehicles, who receives service at separately metered fueling facilities owned by the vehicle owner/operator for the exclusive use of the customer's vehicle(s).

The Customer will install and bear the costs associated with a daily demand reading meter plus all costs associated with dedicated telephone lines and telemetering equipment, and such installation shall be at the expense of the Customer, excluding the cost of the meter.

CHARACTER OF SERVICE

Except as provided herein, a customer under this Rate Schedule may elect either Firm Sales Service, Interruptible Sales Service or Distribution Service.

Where the customer is the owner/operator of a dedicated natural gas vehicle or dedicated fleet of vehicles used to provide public transportation or otherwise used to provide essential public services, the customer must either:

1. Elect firm sales service; or
2. Provide adequate proof of firm pipeline capacity and firm gas supply obtained by the customer, or contract for Standby Service, to be eligible for distribution service during the term of service under this rate schedule.

Under Interruptible Sales Service, the Company takes no responsibility to obtain sufficient gas supplies to avoid interruption on a daily basis, and service is interruptible on any day when the Company has insufficient supply or capacity to provide service. Where feasible, the Company shall give the Customer two hours advance notice of interruption. The Customer agrees that Company shall not be liable for any loss or damage that may be sustained by the Customer by reason of any interruption of service.

Distribution Service hereunder shall be subject to the Rules Applicable to Distribution Service of this tariff.

MAIN LINE EXTENSION DEPOSIT INSTALLMENT PLAN (C)

Applicants eligible for Rate Schedule NGV with projected annual usage greater than 64,440 therms, who have entered into an agreement with the Company to make payments for a main line extension pursuant to the Payment Period of Deposit paragraph in the Capital Expenditure Policy section of Rule 8. Extensions of these Rules and Regulations Governing the Distribution and Sale of Gas, will have the installment amount included in the cyclical bill for service issued by the Company. The installment amount will be added to the Customer Charge for the duration of the installment payment plan.

(C) Indicates Change

RIDER USP – UNIVERSAL SERVICE PLAN – Continued

QUARTERLY ADJUSTMENT

Each quarter, and at any time that the Company makes a change in base rates or Purchased Gas Cost rates affecting residential customers, the Company shall recalculate the Rider USP rate pursuant to the calculation described above to reflect the Company's current data for the components used in the USP rate calculation. The Company shall file the updated rate with the Commission to be effective one (1) day after filing.

ANNUAL RECONCILIATION

On or before April 1 each year, the Company shall file with the Commission data showing the reconciliation (C)
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 CAP quarterly rate adjustment to be effective April 1. Actual recoverable costs shall reflect actual application costs, actual LIURP costs, and actual WarmWise® Audits and Rebates program costs. Actual recoverable costs shall also reflect actual shortfall costs and actual pre-program arrearages, provided that CAP participation on an average annual basis for the preceding year did not exceed 23,000 participants. In the event that CAP participation in the preceding year exceeded 23,000 on an average annual basis, actual recoverable costs shall reflect actual shortfall cost and actual pre-program arrearages for all customers up to the 23,000 participation level. For any and all CAP customers exceeding the 23,000 participation level on an average annual basis, Columbia shall offset the actual shortfall and actual pre-program arrearages by 7.5%. Except for the offset that is applied when CAP participation exceeds 23,000 on an average annual basis, actual CAP shortfall costs shall be based upon actual numbers of CAP customers, actual CAP throughput quantities, actual CAP payments received.

(C) Indicates Change

RIDER PGC - PURCHASED GAS COST (Continued)

COMPUTATION OF PURCHASED GAS DEMAND COSTS PER THM – Continued

Supplier refunds that are not included in "CE" will be included in the calculation of "DE" with interest added at the annual rate of six percent (6%) calculated from the month received to the effective month such refund is refunded. The period over which such refunds will be made shall be established by the Commission.

"S" - projected thms of gas to be billed to customers under the distribution charges of the Rate RSS, Rate SGSS, Rate LGSS, and Rate MLSS rate schedules plus the projected thm of gas to be distributed to customers under Rate RDS, Rate SCD and SGDS Priority One Distribution rate schedules of this Tariff during the period when rates will be in effect.

PROVISION OF PURCHASED GAS DEMAND COST CREDIT DUE TO CUSTOMERS ELECTING CHOICE DISTRIBUTION SERVICE – CAPACITY ASSIGNMENT FACTOR (CAF)

The Purchased Gas Demand Cost (PGDC) rate included in the Pass-through Charge billed to Choice Distribution Service customers served under Rate RDS or Rate SCD shall be $0.07358 per thm. Such rate shall be equal to the PGDC component of $0.10451 per thm as calculated above, less the CAF of $0.03093 per thm. The CAF shall be equal to the projected annual cost of assigned Firm Capacity less estimated annual storage commodity costs (storage injection, withdrawal, shrinkage and commodity transportation cost) with the net divided by the estimated, normalized annual usage of customers electing Choice Distribution Service. The CAF of $0.03093 per thm representing costs not assignable to CHOICE customers shall be included in the Price-to-Compare.

DETERMINATION OF OVER/UNDERCOLLECTION OF GAS COSTS

Commodity E-factor

In computing the experienced over/under collection of purchased gas commodity costs for a period defined by the Commission, the following procedure shall be used:

(a) All experienced purchased gas commodity costs actually incurred by the Company to service customers pursuant to all rate schedules of this Tariff.

Experienced purchased gas commodity costs shall include, but not be limited to, the following:

(1) payments to suppliers to accept assignment of capacity on interstate pipelines other than Columbia Gas Transmission, LLC to the extent permitted under the Rules Applicable to Distribution Service; (C)

(2) costs paid for employing futures, options and other risk management tools, including but not limited to, supplier related costs associated with the fixed price contracts or financial contracts utilized by the Company to lessen the impact of price volatility for PGC customers; and

(3) the index price of gas purchased from distribution customers under the provisions of the Deliveries in Excess of Consumption section of Paragraph 3 of the Rules Applicable to Distribution Service.

RIDER PGC - PURCHASED GAS COST (Continued)

DETERMINATION OF OVER/UNDERCOLLECTION OF GAS COSTS - Continued

Demand "E" Factor – Continued

(4) credits received for capacity assigned pursuant to the Rules Applicable to Distribution Service; plus

Interest on over/under collection of gas costs shall be computed monthly at the appropriate rate provided for in Section 1307(f)(5) of the Public Utility Code from the month that the over or undercollection occurs to the effective month such over or undercollection is refunded.

ADJUSTMENT OF "E" FACTOR AMOUNTS

Each 1307(f) rate shall also provide for refund or recovery of amounts necessary to adjust for over or underrecoveries of "E" Factor amounts included in prior 1307(f) rates. In computing the amount to be included for over or undercollection of "E" Factor amounts, the amount recovered for "E" Factor amounts under the prior 1307(f) rate shall be determined by multiplying the applicable Distribution quantities billed under the Rate CAP, Rate RSS, Rate SGSS, Rate LGSS, Rate MLSS, Rate RDS, Priority One Rate SGDS, and Rate SCD rate schedules during the applicable 1307(f) period times the portion of the PGCC and the PGDC component that provides for recovery of "E" Factor amounts.

SUPPLIER REFUNDS APPLICABLE TO RATE SS CUSTOMERS

Any supplier refunds received from Columbia Gas Transmission LLC, which are specifically identified as (C)
refunds of Contract Demand charges made after March 31, 1992, shall be refunded pro rata to customers taking service during the applicable prior period(s) under Rate SS. All refunds shall include interest added at the annual rate of six percent (6%) calculated from the month received to the month the refund is made. Refunds shall be paid once each year, as soon as practicable following October 30 of each year, and shall include all applicable supplier refunds received by the Company during the preceding twelve-month period ended October 30.

SHARING OF OFF-SYSTEM SALES REVENUE

Following is the definition of gas cost for off-system sales program.

(1) For sales in which a specific purchase is not made, the cost of gas will be defined as the daily average city gate commodity cost of the gas supplies purchased by the Company and flowing on the first of the month (WACCOG). For sales made upstream of the Company's city gate, the cost of transportation, including retainage, from the point of sale to the city gate will be subtracted from the WACCOG. This amount will be further adjusted to include applicable taxes, other than income taxes, and other costs.

(2) For incremental sales in which a specific purchase is made, the cost of gas will be defined as the purchase price plus transportation costs, including retainage, taxes and other costs that have or will be incurred.

(C) Indicates Change

PURCHASED GAS COST RIDER (Continued)

GAS PROCUREMENT INCENTIVE PROGRAM

The gas procurement incentive program will be limited to spot gas purchased for the months of April through October. Each month the Company's actual cost will be compared to an adjusted NYMEX index for such month.

The adjusted NYMEX index will be determined by averaging the month end closing prices reported for the last three days of trading on NYMEX after adjusting these prices for the differential between the average of indices representing cash prices paid on such days at the Henry Hub, for gas to be delivered on the first day of the month, and the average of indices prices representing the specific delivery points where Columbia takes title to its gas supply. In any instances where indices are not published in any one of the three chosen publications for a receipt point where the Company purchases spot gas, then the index used will be (1) Columbia Gas Transmission, LLC's Appalachian Index average used at points of delivery into Columbia Gas Transmission, LLC; (2) Columbia Gas Transmission, LLC's Appalachian Index average plus Columbia Gas Transmission, LLC's Storage Service Transportation commodity costs used at points of delivery out of Columbia Gas Transmission, LLC; or (3) if the first two are not appropriate, the price paid will be adjusted by deducting a 100% load factor firm transportation rate to the most applicable receipt point where an index is available. The index and Henry Hub prices utilized will be an average of first of the month prices reported in *Inside F.E.R.C.'s Gas Market Report*, *Natural Gas Week* and *Natural Gas Intelligence*. (C)

A band of ninety-nine (99%) to one-hundred one percent (101%) will be applied monthly to the average indexed prices, as described above, to be compared to the Company's actual prices paid for spot gas purchased to flow during the month to determine the appropriate monthly retention of savings or absorption of losses. The Company will share savings 50%/50% between customers and the Company for increments of actual gas purchases below ninety-nine percent (99%) of the adjusted NYMEX index. The Company will absorb losses 50%/50% between customers and the Company for increments of actual gas purchases above one-hundred one percent (101%) of the adjusted NYMEX index. If the actual gas purchases fall within the band, there will be no sharing.

This program will be in effect from October 1, 2002 through September 30, 2004, unless extended by the Company with approval of the Commission.

RATE NGV GAS COST CREDIT

The following purchased gas cost credits shall be provided for all gas sold under the NGV rate schedule:

1. Demand Costs
   For firm sales under Rate NGV, an amount per thm for recovery of demand costs determined as follows:

$$\frac{\text{Annual Demand Costs}}{(\text{Maximum Daily Quantity x 365}) \text{ x Average NGV Load Factor}}$$

   Where:

   a. Annual Demand Costs equal the total annual demand charges for supply and capacity included in the Company's purchased gas cost rates under the Purchased Gas Cost Rider, and

   b. Maximum Daily Quantity equals maximum firm deliveries that can be made by the Company to its customers during the winter period.

(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	1.52%	(D)
Non-residential uncollectible expense ratio	0.37%	(D)

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.

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 0.000%. (C)

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

RIDER EBS – ELECTIVE BALANCING SERVICES

APPLICABILITY

Throughout the territory served under this Tariff.

AVAILABILITY

This Rider has been established to provide balancing service options for General Distribution Service (GDS) customers in Pennsylvania.

In addition to the charges provided in the customer's rate schedule, an amount may be added to the otherwise applicable charge for each thm of distribution quantities distributed by the Company to a customer receiving service under Rate Schedules SGDS, SDS, LDS, and MLDS, or successor rate schedules, for EBS service as provided below. Rider EBS contains two options for balancing service as described below.

SERVICE OPTIONS:

Option 1: FULL BALANCING SERVICE

Full Balancing Service provides the Customer Proxy with the opportunity to: (1) maintain a bank from month to month on the Company's system; (2) access banked gas on a firm basis pursuant to the Seasonal Flow Order, Operational Flow Order, and Matching Flow Order sections in Paragraph 3 of the Rules Applicable to Distribution Service ("RADS") on any day, including days in which an SFO, OFO, or OMO restricts GDS under-deliveries, up to five percent (5%) of the customer's currently effective Maximum Daily Quantity (C)
("MDQ"), and, to the extent made available by the Company on a best efforts basis, additional interruptible access to the Customer Proxy's bank and (3) to add to the bank on any day, including days in which an SFO, OFO, or OMO restricts GDS over-deliveries. Deliveries to the Company on days in which an SFO, OFO or OMO restricts over-deliveries shall not exceed one hundred two and one-half percent (102.5%) of the maximum prescribed SFO, OFO, or OMO Level unless authorized by the Company.

Option 1: BANK TOLERANCE

The cumulative balance of excess deliveries ("positive bank"), at the end of any billing month, shall not exceed the following specified Bank Tolerance Percentages:

1. For any customer with annual consumption greater than 540,000 thm - 5% of the customer's then current annual quantities.

2. For any customer with annual consumption less than or equal to 540,000 thm --- 10% of the customer's then current annual quantities as specified for the billing months of November through September, and 5% of the customer's then current annual quantity for the October billing month.

(C) Indicates Change

RIDER EBS – ELECTIVE BALANCING SERVICES (Continued)

Option 1: RATES

The rates for EBS-Option 1 will be calculated on an annual basis by the Company. The Company shall calculate the rates after Customer Proxies have elected their service options and after the Company has secured the assets that are required to provide the service. The Company shall file the rates with the Commission to take effect on April 1 of each year upon one day's notice. The rates for service commencing April 1, 2005 are specified in the Rate Summary Section of this tariff.

The Company may reduce or eliminate the otherwise applicable charge for Rider EBS-Option 1 to any customer if it is reasonably necessary to do so to meet competition from an alternative fuel, including gas from another supplier of gas that has constructed, or could construct, facilities to deliver gas to the customer without use of the Company's facilities. The Company will notify the Customer Proxy of the applicable rate if lower than the applicable rate set forth above, at least four (4) days prior to the beginning of each billing month, unless the rate is the same as charged by the Company in the prior month. Such reduction or elimination of the charge shall be reduced before any reduction is made to the other charges under this tariff.

The rates identified in this section billed and collected pursuant to Option 1 shall not be credited toward recovery of purchased gas costs pursuant to the Purchased Gas Cost Rider.

Option 1: ELECTING SERVICE

Option 1 is the default service option under Rider EBS. Any customer whose Customer Proxy has not elected to take service under one of the other options shall automatically take service under Option 1. A Customer Proxy for an existing GDS customer may elect to change its service option no more than one time per year. An estimate of the rates shall be posted on the Company's EBB on August 1 of each year. All requests to change the service option must be submitted to the Company in writing (e.g. fax, e-mail, electronic bulletin board) no later than the fifteenth of August prior to the April in which the elected option becomes effective. The EBS-Option 1 final rate will be posted on the Company's EBB on September 1. If the September 1 final rate exceeds the August 1 estimated rate by more than 20%, Customer Proxies who have elected EBS-Option 1 may change their election by submitting a change to the Company in writing (e.g. fax, e-mail, EBB) no later than the fifteenth of September. The elected option shall remain in effect for the one-year period commencing April 1 of the following calendar year. A Customer Proxy for a new GDS customer shall elect its service option at the time it executes its General Distribution Service Application and Agreement; however, if the new GDS customer executes its General Distribution Service Application and Agreement after August 15, the Company is under no obligation to provide service to the customer under Option 1 until April of the next following year if the Company does not have adequate storage and capacity assets to provide the service. If the Company cannot serve the new GDS customer under Option 1 until April of the next following year, the Company will either: (a) serve the customer under Option 2 during the interim; or (b) elect to limit/reduce the Elective Balancing Services under Option 1 for (C)
the new GDS customer.

Columbia's obligation to provide service under Option 1 is conditioned upon its ability to secure the assets necessary to provide the service. If sufficient assets are not available to provide Option 1 service, customers will default to Option 2.

(C) Indicates Change

RIDER EBS – ELECTIVE BALANCING SERVICES (Continued)

Option 1: FULL BALANCING SERVICE (Continued)

Option 1: CHARACTER OF SERVICE

Normal Operations

In any billing month under Normal Operations (defined as operations during times when neither an SFO, OFO nor an OMO is in effect), if the customer's consumption plus retainage on the distribution system is greater than the sum of: (a) the quantity of gas delivered to the Company's City Gate by the Shipper for the Customer Proxy's account during the billing month, plus (b) the Customer Proxy's positive bank at the beginning of the month, such use shall be considered imbalance gas sold by the Company to the Customer Proxy under the provisions of the Consumption in Excess of Deliveries section in the Rules Applicable Only to General Distribution Service section of the RADS .

If in any billing month under Normal Operations, the customer's consumption plus retainage on the distribution system is less than the quantity of gas delivered into the Company's system on its behalf, the Customer Proxy may use such excess delivered gas to meet requirements in any succeeding billing month, subject to the Company's rights to limit service as provided in the RADS. Provided, however, that the cumulative balance of excess deliveries ("positive bank"), at the end of any billing month, shall not exceed the Bank Tolerance Percentage. Any positive bank in excess of this tolerance level shall be considered imbalance gas purchased by the Company from the Customer Proxy under the provisions of the Deliveries in Excess of Consumption section in the Rules Applicable Only to General Distribution Service section of the RADS.

During SFOs/OFOs/OMOs

During periods when there is an SFO, OFO or OMO that restricts GDS under-deliveries, EBS Option 1 Customer Proxies will have firm daily access to banks equal to five percent (5%) of the customer's
currently effective Maximum Daily Quantity ("MDQ"). Additional interruptible access to bank capacity will (C)
be available on a best-efforts basis. Should a Shipper on any SFO, OFO, or OMO day under-deliver gas
supplies to the Company by a quantity greater than 5% of the customer's currently effective MDQ and any (C)
interruptible access to the bank permitted through the SFO, OFO or OMO notice, such quantities shall be charged to the Customer Proxy in accordance with the Consumption in Excess of Deliveries, Seasonal Flow Orders, Operational Flow Orders or Operational Matching Orders sections of the Rules Applicable Only to General Distribution Service section of the RADS as is appropriate to the circumstance. If on any day, the Customer Proxy's bank is not adequate to support any part or all of the bank access made available by the Company and the resulting bank availability combined with other confirmed deliveries by the Shipper is less than the daily delivery requirement under the SFO, OFO, or OMO, the Customer Proxy will be
charged for any delivery deficiency in accordance with the Seasonal Flow Order, Operational Matching (C)
Order, Operational Flow Order and Consumption in Excess of Deliveries sections in the RADS. At the end (C)
of any month in which there has been an SFO, OFO, or OMO that restricts GDS under-deliveries, authorized bank withdrawals used to help meet the daily delivery requirements of an OFO or OMO will be deemed to be the first gas withdrawn from the bank, followed by authorized bank withdrawals used to help meet the daily delivery requirements of an SFO during the month. Any remaining available bank quantities will be applied to days of Normal Operations. Authorized bank withdrawals herein are considered to be the firm access provided under EBS Option 1 plus any interruptible access provided by the Company subject to the Customer Proxy(s) having sufficient quantities in its (their) bank to support the access permitted by the Company.

(C) Indicates Change

RIDER EBS – ELECTIVE BALANCING SERVICES (Continued)

Option 1: FULL BALANCING SERVICE (Continued)

Option 1: TERMINATION OF SERVICE

Customer Proxies may terminate service under Option 1 only by electing another option in accordance with the provisions set forth in this Rider or by terminating GDS service. A Customer Proxy whose Customer is terminating GDS service may be charged a termination fee if the Customer Proxy fails to provide termination notice prior to the fifteenth of September prior to the April in which the service is to be terminated. Such termination fee shall be based upon the cost of the assets secured by the Company to provide service to the Customer. Upon termination of service under Option 1, the Company will make every effort to deliver to the Customer Proxy the Customer Proxy's banked gas during the next month's billing cycle following the date of termination. However, should Customer Proxy fail to take delivery of its entire bank of gas within the next month, Company may, at its option, retain and purchase the undelivered bank of gas at a rate determined pursuant to the Deliveries in Excess of (C) Consumption paragraph in the Rules Applicable Only to General Distribution Service section of the RADS. In addition, if the Customer Proxy owes the Company any outstanding charges, the Company may retain as an offset to such outstanding charges, banked gas that would otherwise be delivered to Customer Proxy upon termination of GDS service. The value assigned to such retained bank of gas which is purchased or retained will be a rate determined pursuant to the Deliveries in Excess of Consumption paragraph in the Rules Applicable Only to General Distribution Service section of the (C) RADS for the month in which the Customer Proxy failed to take delivery of the gas.

1. DEFINITIONS (Continued)

1.22 "Firm Service" with regard to Natural Gas Supply services shall mean the quality of Natural Gas Supply Service provided to the Customer in which gas shall be available at all times, even under adverse conditions. "Firm Service" with regard to Natural Gas Distribution Company services shall mean that the Company will distribute gas to the Customer on a firm basis during any day in which the Customer's gas is delivered by the Shipper to the Company at a Delivery Point in the same Company Local Market Area in which the Customer's facilities are located, as further defined in Paragraph 2.6 of these Rules Applicable to Distribution Service.

1.23 "FTS" shall mean firm transportation service provided by an interstate pipeline in which gas is transported on a firm basis from designated receipt points to designated delivery points.

1.24 "Gas" or "Natural Gas" or "Natural Gas Supply" or "Gas Supply" shall mean the hydrocarbon gas obtained from underground and undersea porous sedimentary rocks. In these Rules Applicable to Distribution Service these terms will refer to the commodity an NGS nominates and schedules for delivery to the Company for distribution.

1.25 "General Distribution Aggregation Service" shall mean the aggregation of General Distribution Service Customers in a group for the purpose of administering gas purchase and supply.

1.26 "General Distribution Application and Agreement" shall mean the Application completed by a Customer who desires to begin taking General Distribution Service.

1.27 "General Distribution Service" and "GDS" shall mean Distribution service provided under rate schedules DGDS, CDS, EGDS, LDS, MLDS, NCS, SGDS, or SDS.

1.28 "Historical Billing Data" shall mean the minimum of twelve (12) months of data as recorded by the Company, which contains usage data and dollar amount billed, unless 12 months of such data is not available.

1.29 "Initial NGS Application" shall mean the initial application that must be made to the Company by the NGS prior to providing either General Distribution Service or Choice Service.

1.30 "ITS" shall mean interruptible transportation service provided by an interstate pipeline, in which natural gas is transported on an interruptible basis.

1.31 "Local Market Area" shall mean a continuous, physically-interconnected system of Company-owned distribution piping through which the Company provides natural gas service to Customers in a discrete geographic area, utilizing one or more common Delivery Points from interstate pipeline supplier(s) or local gas supplier(s).

1.32 "Material Obligation" shall mean any obligation of the NGS under these Rules Applicable to Distribution Service, which if not fulfilled by the NGS, would impair the Customer's Natural Gas Supply Services or would impair the Company's ability to provide natural gas distribution services to its Customers.

(C) Indicates Change

1. DEFINITIONS (Continued)

1.33 "Maximum Daily Quantity" or "MDQ" shall mean a General Distribution Service Customer's maximum usage during a 24-hour period based on the most recent historical Customer consumption data. The Company will establish a winter MDQ for the November through March time period and a summer MDQ for the April through October time period. However, an adjustment may be made at any time upon agreement of the Customer and the Company. (C)

1.34 "month" shall mean calendar month.

1.35 "Natural Gas Distribution Company" or "NGDC" shall mean a public utility or city natural gas distribution operation that provides natural gas distribution services and which may provide natural gas supply services and other services. For purposes of this standard of conduct, the term does not include:

(i) A public utility subject to the jurisdiction of the Commission which has annual gas operating revenues of less than $6 million per year, except:

(A) When the public utility voluntarily petitions the Commission to be included within the definition of an NGDC.

(B) When the public utility seeks to provide natural gas supply services to retail gas customers outside its service territory.

(ii) A natural gas public utility subject to the jurisdiction of the Commission that is not interconnected to an interstate gas pipeline by means of a direct or indirect connection through the distribution system of another natural gas public utility or through a natural gas gathering system.

1.36 "Natural Gas Provider" or "NGP" shall mean the NGDC, NGS, marketer, aggregator and/or broker, as well as any third party acting on behalf of these entities.

(C) Indicates Change

1. DEFINITIONS (Continued)

1.37 "Natural Gas Supplier" or "NGS" shall mean an entity other than a natural gas distribution company, but including natural gas distribution company marketing affiliates without regard to structural relationship, which provides natural gas supply services to retail gas customers utilizing the jurisdictional facilities of a natural gas distribution company. The term includes:

(i) A natural gas distribution company that provides natural gas supply services outside its certificated service territories.

(ii) A municipal corporation, its affiliates or any joint venture, to the extent that it chooses to provide natural gas supply services to retail customers located outside of its corporate or municipal limits, as applicable, other than:

(a) As provided prior to July 1, 1999, the effective date of 66 Pa.C.S. Chapter 22 (relating to natural gas competition), under a certificate of public convenience if required under this title.

(b) Total natural gas supply services in de minims amounts.

(c) Natural gas supply services requested by, or provided with the consent of, the public utility in whose certificated territory the services are provided.

(d) Natural gas supply services provided to the municipal corporation itself or its tenants on land it owns or leases, or subject to an agreement of sale or pending condemnation, as of September 1, 1999, to the extent permited by applicable law independent of 66 Pa.C.S. Chapter 22.

(iii) The term excludes an entity to the extent that it provides free gas to end-users under the terms of an oil or gas lease. Notwithstanding any other provision of 66 Pa.C.S. (relating to the Public Utility Code), an NGS that is not an NGDC is not a public utility as defined in 66 Pa.C.S. §102 (relating to definitions) to the extent that the NGS is utilizing the jurisdictional distribution facilities of an NGDC or is providing other services authorized by the Commission.

1.38 "Natural Gas Supply Services" shall mean the sale or arrangement of the sale of natural gas to retail customers and services that may be unbundled by the Commission under section 2203(3) of the Act. The term does not include distribution service.

1.39 "NGS Choice Distribution Aggregation Agreement" shall mean the contract between the NGS and the Company that specifies the terms and conditions for participation in the Choice Service.

1.40 "Nomination EBB" shall mean the electronic bulletin board and nomination system, which is used for scheduling deliveries of gas on the Company's system.

1.41 "Paragraph" shall mean a numbered paragraph of these Rules Applicable to Distribution Service as well as all sub-paragraphs falling under that numbered paragraph.

(C) Indicates Change

1. DEFINITIONS (Continued)

1.42 "Primary FTS" with regard to Columbia Gas Transmission, LLC capacity, shall mean FTS which has a designated primary delivery point located in the same Pipeline Scheduling Point in which the Customer is located and has a designated primary receipt point at a location considered to be a point of generally available supply. "Primary FTS" with regard to any other transmission pipeline shall mean firm transportation service which has a designated primary delivery point located in the same Company Local Market Area in which the customer is located and has a designated primary receipt point at a location considered to be a point of generally available supply. (C)

1.43 "Reliability" comprises adequacy and security.

1.44 "Retainage" shall mean gas lost and unaccounted for in the Company's operations as more specifically defined in the Retainage paragraph of these Rules Applicable to Distribution Service.

1.45 "Rules and Regulations" shall mean the "Rules and Regulations Governing the Distribution and Sale of Gas" section of the Company's tariff.

1.46 "Security" means designing, maintaining and operating a system so that it can safely handle extreme conditions, as well as emergencies.

1.47 "Shipper" generally means the entity nominating gas service for distribution. Specifically, "Shipper" is defined as:

1.) a General Distribution Service Customer that nominates gas for Distribution; or

2.) a Natural Gas Supplier that nominates the General Distribution Service Customer's gas for distribution, but which has not been appointed in writing as the Customer's agent by the Customer; or

3.) a Natural Gas Supplier that nominates the General Distribution Service Customer's gas for distribution, which NGS is acting as the General Distribution Service Customer's duly authorized agent for the purpose of purchasing gas; or

4.) a Natural Gas Supplier that nominates the General Distribution Service Customer's gas for Distribution, which NGS is acting as the General Distribution Service Customer's duly authorized aggregation agent for the purpose of purchasing gas.

1.48 "Storage" shall mean placing natural gas into an underground facility for removal and use at a later date.

1.49 "Transmission" shall mean the moving of natural gas through the interstate pipeline system for delivery to the NGDC.

(C) Indicates Change

2. RULES APPLICABLE TO ALL DISTRIBUTION SERVICE

2.1 This Paragraph applies to all distribution service on the Company's system, regardless of whether the Customer is acting as its own Shipper or whether the Customer has contracted with an NGS to provide this service.

2.2 ELECTRONIC COMMUNICATIONS.

2.2.1 All nominations must be performed through the Company's Nomination EBB.

2.3 INITIAL NGS APPLICATION

2.3.1 All NGSs must complete an Initial NGS Application in the form prescribed by the Company, and have it approved by the Company prior to being able to supply gas for either General Distribution Service or Choice Service on the Company's system. NGSs may be required by the Company to resubmit the Initial NGS Application in instances where changed circumstances cause the Initial NGS Application to no longer be applicable. Such changed circumstances include, but are not limited to circumstances such as: a change in the financial status of the NGS, a substantial change in the number of Customers being served by the NGS, or a substantial change in the amount of natural gas being provided by the NGS.

2.3.2 All NGSs must be licensed by the Commission prior to the Company's approval of the Initial NGS Application to provide Natural Gas Supply Services on the Company's system. Pursuant to Section 2208 of the Public Utility Code, 66 Pa. C.S. §2208, no entity shall engage in the business of an NGS unless it holds a license issued by the PUC. NGS license application packages can be found on the PUC web site at http://puc.paonline.com. PA. P.U.C. Docket No. M-00991248F0002.

2.3.3 Absent a Commission waiver, all parties must adhere to the applicable Chapter 56 standards when they engage in an activity covered by those standards. 52 Pa. Code Ch. 56. NGSs should also refer to the Commission's guidelines on Maintaining Customer Services at the Same Level of Quality Pursuant to 66 Pa. C.S. § 2206(a), Docket No. M-00991249F0003.

2.3.4 As part of the Initial NGS Application process, an NGS must meet the standards and fulfill the obligations of creditworthiness as required under the NGS Creditworthiness paragraph of these Rules Applicable to Distribution Service before being permitted to provide Natural Gas Supply Services on the Company's system.

2. RULES APPLICABLE TO ALL DISTRIBUTION SERVICE – continued

2.4 NGS CREDITWORTHINESS

2.4.1 The Company will require the NGS to provide financial information in order for the Company to establish the NGS's creditworthiness. The NGS shall provide the Company with the financial information that it provided to the Commission, as well as the NGS's most current financial information. In addition, the Company may request the NGS to furnish the following financial information:

- Credit reports,
- Bank References,
- Audited Financial Statements, Annual Report, 10K or 10Q prepared in the past 12 months,
- Confirmation that the NGS is not operating under any bankruptcy or insolvency law,
- Confirmation that no significant lawsuits or judgements are outstanding,
- Confirmation that the NGS is not aware of any adverse condition which could cause a material change in financial condition,
- A list of parent company and other affiliates,
- Names, addresses and telephone numbers of three trade references, and/or
- Additional financial related information as determined by the Company.

2.4.2 The creditworthiness evaluation will be based on standard credit factors such as previous operating history including operating history on other NGDC's when applicable, financial and credit ratings from investment rating companies, trade references, unused line of credit, financial information and number and class of customers to be served. The Company shall determine creditworthiness based on the above criteria but will not deny creditworthiness without reasonable cause.

2. RULES APPLICABLE TO ALL DISTRIBUTION SERVICE – continued

2.4 NGS CREDITWORTHINESS - continued

2.4.3 Amount and Form of Security (C)

The criteria for determining the amount and form of security will be based on criteria specified in Title 52 §62.111 (c) of the Pennsylvania Code.

2.4.3.1 The following legal and financial instruments and property shall be acceptable as security:

(i) Bond;

(ii) Irrevocable letter of credit;

(iii) Corporate, parental or other third-party guaranty;

(iv) Escrow account;

(v) Accounts receivable pledged or assigned to the Company by a licensee participating in the Company's purchase of receivables program that has been approved by the Commission as being consistent with Commission orders, guidelines and regulations governing the programs;

(vi) Calls on capacity, netting the Company's gas supply purchases from the NGS against NGS security requirements, or other operational offsets as may be mutually agreed upon by the Company and the NGS; and

(vii) Cash.

2.4.3.2 In addition to the requirements specified above, small suppliers with annual operating revenues of less than $1 million may utilize real or personal property as security with the following supporting documentation:

1. A verified statement from the licensee that it has clear title to the property and that the property has not been pledged as collateral, or otherwise encumbered in regard to any other legal or financial transaction; and

2. A current appraisal report of the market value of the property.

The security amount may be modified. An adjustment to the amount of security may be requested by the Company or the NGS as specified in Title 52 §62.111 (c) (6) and (7) of the Pennsylvania Code.

(C) Indicates Change

2. RULES APPLICABLE TO ALL DISTRIBUTION SERVICE – continued

2.4 NGS CREDITWORTHINESS – continued

2.4.4 Calculation of the Security Requirement

The following is a calculation of the Natural Gas Supplier's (NGS) Security Requirement. The NGS Financial Exposure is the sum of one month's commodity exposure, plus one month's capacity exposure. The Security Requirement ("SR") is the NGS Financial Exposure ("FE") less any Unsecured Credit Level ("UCL"), Accounts Receivable Credit ("ARC") or Current Collateral ("CC").

SR = FE – (UCL + ARC + CUC), where
FE = COE + CAE, and
COE = {(ARCC x RC x CR) + (ACCC x CC x CR), and
CAE = FT x FTR, and
ARC = {(NGSAR x ARCC x RC) + (NGSAR x ACCC x CC)}

An Accounts Receivable Credit is applied only when Columbia has been provided first secured interest. The NGS shall provide Columbia with any additional documents and take any additional steps that Columbia may request to perfect Columbia's interest.

Columbia will perform the above calculations monthly. The Security Requirement may be adjusted as circumstances warrant and in accordance with Chapter 62 – Natural Gas Supply Customer Choice, Subchapter D, Liscensing Requirements for Natural Gas Suppliers.

In computing the amount of security required of the NGS pursuant to the formula above, the following definitions shall apply:

ARC equals Accounts Receivable Credit (if applicable).

ARCC equals Average Residential Customer Consumption.

ACCC equals Average Commercial Customer Consumption.

CAE equals capacity exposure (in $).

CC equals number of Commercial Customers.

COE equals commodity exposure (in $).

CR equals the Commodity rate calculated using the Inside FERC's Gas Market Report "Columbia Gas, App" index rate for prices of spot gas purchased at the Columbia Gas Transmission pool for the first of the month plus the current Columbia Gas Transmission shrinkage and commodity charges. (C)

CUC equals Current Collateral (in $) (if applicable).

(C) Indicates Change

2. RULES APPLICABLE TO ALL DISTRIBUTION SERVICE - continued

2.22 Platts "Gas Daily", Daily Price Survey - Designation by Pipeline Scheduling Point (C)

The table below will be used to identify the specific price indices for each pipeline scheduling point, the higher of which will be used as the starting point for calculating charges for non-compliance with Operational Flow Orders, Operational Matching Orders and/or failure to deliver the Choice Daily Delivery Requirement. The physical location of the customer's service address will determine the pipeline scheduling point used in calculating the non-compliance charge(s).

Platts "Gas Daily", Daily Price Survey				
Pipeline Scheduling Point	Columbia Gas, App.	Dominion North Point	Tennessee Zone 4 – 200 Leg	Texas Eastern M-3
25 - Lancaster	X			X
26 - Bedford	X		X	
29 - Downington	X			X
35 - Pittsburgh	X		X	
36 - Olean	X			X
38 - Rimersburg	X		X	
39 - New Castle	X		X	
40 - PA/WV Misc	X		X	

(C) Indicates Change

3. RULES APPLICABLE ONLY TO GENERAL DISTRIBUTION SERVICE

3.1 This Paragraph applies to all General Distribution Service on the Company's system, regardless of whether the Customer is acting as its own Shipper or whether the Customer has contracted with an NGS to provide this service.

3.2 APPLICATION PROCESS

3.2.1 All Customers must complete an application in the form prescribed by the Company prior to taking service under these Rules Applicable to Distribution Service ("General Distribution Application and Agreement"). The General Distribution Application and Agreement shall set forth: (1) the point(s) of receipt at which the gas will be delivered to the Company; (2) the point(s) to which the Company will distribute the gas to the Customer's facilities; and (3) the Customer's currently effective Maximum Daily Quantity and annual quantity. The General Distribution Application and Agreement shall also include: the name, address and telephone number to which all notices are to be delivered, an e-mail address, banking and balancing information if applicable, alternate fuel information, the service and levels of said services to be rendered. (C)

The currently effective Maximum Daily Quantity and annual quantity are subject to adjustment by the Company no more than one time each year, to reflect the Customer's currently effective Maximum Daily Quantity and annual quantities experienced in the most recent November to October period, except an adjustment may be made at any time upon agreement of the Customer and the Company.

3.2.2 In the General Distribution Application and Agreement, the Customer has the option of appointing an NGS to act on its behalf, for the purpose of establishing and administering the Customer's General Distribution Service. This appointment shall authorize the NGS to administer the Customer's purchase of natural gas supplies, including (by way of illustration and not limitation) the following: obtain the Customer's historic and current usage data from the Company; place a Customer in an Aggregation Nomination Group; receive notices on behalf of the Customer; nominate gas on behalf of the Customers; and obtain from the Company any and all pertinent information pertaining to prior or current month gas deliveries to the Customer, including disbursed quantities, tariff quantities, banked quantities and bank tolerances. The Customer has the right to change his appointment of an NGS to act on his behalf by submitting a new General Distribution Application and Agreement containing the new appointment.

3.2.3 The benefits and obligations of service under these Rules Applicable to Distribution Service shall begin when the Company first receives gas on the Customer's behalf.

3.2.4 Within sixty (60) days of receipt of all necessary information requested by the Company to evaluate a Customer's application, the Company will respond to the General Distribution Application and Agreement and agree either to supply service or deny service. If the Company refuses to provide service under the requested rate schedule, the Company shall provide detailed support for its decision. (C)

(C) Indicates Change

3.2.5 The NGS is not required to complete an application to provide General Distribution Service; provided that the Customer's NGS submitted an Initial NGS Application which was approved by the Company.

3.3 CHARACTER OF SERVICE TO BE RENDERED

3.3.1 The Company shall receive the quantities of gas supplied by the Shipper and shall redeliver said gas to Customer's facilities. For Customers who purchase 100% Standby Service, the Company will provide Firm Service up to the Customer's currently effective Maximum Daily Quantity. For Priority One Customers, the Company will provide Firm Service. (C)

3.3.2 Special Conditions for Customers with less than 100% Standby Service:

3.3.2.1 Customers may request to take General Distribution Service with less than 100% Standby Service provided that the Customer agrees to the following conditions:

3.3.2.1.1 Interruption of gas distribution may occur if the Shipper fails to deliver sufficient quantities of gas to the Company, including sufficient quantities to cover peak day usage, whether or not such failure is due to the fault of Shipper. Interruptions or limitations may be necessary during peak day conditions even if all of the Customer's gas has been delivered to the Company.

3.3.2.1.2 An interruption of gas deliveries may require or result in (1) the temporary closing of the Customer's facilities, (2) lost production, sales, or business, and (3) damage to Customer's physical facilities. The Customer assumes the risk of any such losses or damage. A failure of the Customer to interrupt after notification to the Customer Proxy by the Company may also subject the Customer Proxy to liability for fines or penalties incurred by the Company as a result of such failure.

(C) Indicates Change

Ratio of Under-Deliveries to Consumption	Adjustment to Index Price
0% - 10.00%	120%
10.01% and over	130%

(2) If a Shipper over-delivers during an SFO that restricts over-deliveries, the charge for over-deliveries shall be calculated using the gas supply index identified in the Deliveries in Excess of Consumption section in this Paragraph 3 of the RADS; The "Adjustment to Index Price" shall be the adjustment shown in the following table:

Ratio of Over-Deliveries to Consumption	Adjustment to Index Price
0% - 10.00%	80%
10.01% and over	70%

(3) The Customer Proxy shall also be required to pay all other charges incurred by the Company on the dates of the SFO that result from the Shipper's failure to comply with the SFO, including a proportionate share of any pipeline penalties that are incurred by the Company.

3.7 OPERATIONAL FLOW ORDERS (OFOs)

3.7.1 An OFO is a demand for specific actions on the part of Shippers that are serving Customers without daily measuring devices. All Customers without daily measuring devices are subject to the Company's issuance of OFOs.

3.7.2 An OFO will be issued, to the extent possible, with a minimum of eight (8) hours notice to the affected parties. Notice shall be made by the medium most reasonably expected to reach the Customer Proxy with as much notice as reasonably expected to reach the Customer Proxy in a timely manner, including but not limited to: e-mail, facsimile, or Nomination EBB. The notice will include the circumstance that warrants the issuance of the OFO or OMO, and it will explain why the actions are necessary. The notice will be provided via e-mail to the Pennsylvania P.U.C.

3.7.3 The Company will have the authority to direct Customer Proxies to direct their Shippers to adjust daily quantities to a specified level (the Daily OFO Level). Generally, during peak design day conditions, the Daily OFO Level will be equal to the currently effective Maximum Daily Quantity. (C)
Should expected conditions be different than peak design day conditions, the Daily OFO Level may be greater or less than the currently effective Maximum Daily Quantity specified in the (C)
Customer's General Distribution Application and Agreement. In order to determine compliance with the OFO the Shipper may use gas quantities which are: 1) scheduled and delivered on that day to the Company in the same Pipeline Scheduling Point in which the Shipper's customer(s')'s facilities are located; 2) contracted for under Rate SS – Standby Service if the order is pertaining to an under-delivery situation; 3) available pursuant to the Rider EBS-Option 1; or 4) additional (C)
quantities that may be made available to the Shipper by the Company at its sole discretion including quantities delivered in accordance with the Limitation for Failure of Shipper to Provide Gas to the Company in Customer's Local Market Area section in Paragraph 2 of the RADS.

(C) Indicates Change

3.7 OPERATIONAL FLOW ORDERS (OFOs) - continued

3.7.4 When a difference between the Daily OFO Level and actual daily OFO compliance quantities delivered to the Company exists, the following charges will be assessed to the Customer Proxy:

(1) A rate equal to three times the highest of the midpoint prices reflected in Platts Gas Daily for the day of the OFO non-compliance and based on pipeline scheduling point applicable indices as specified in the Platts "Gas Daily", Daily Price Survey – Designation by Pipeline Scheduling Point paragraph of Rule 2. Rules Applicable to All Distribution Service in the Rules Applicable to Distribution Service of this tariff. (C)

The charge will be multiplied by the therm difference, except however, the charge will not be assessed if the difference results from the Shipper delivering more than the Daily OFO Level during an OFO that restricts under-deliveries, or from the Shipper delivering less than the Daily OFO Level during an OFO that restricts over-deliveries; and, (C)

(2) The payment of all other charges incurred by the Company on the date of the OFO that results from the Shipper's failure to comply with the OFO, including a proportionate share of any pipeline penalties that are incurred by the Company.

(3) In the event midpoint prices referenced in subparagraph (1) above, are not published in Platts Gas Daily for the day of the OFO non-compliance, the highest price paid by the Company on that day shall be used as the index price. (C)

(4) The Company shall update the applicable indices on 60 days' notice to Customer Proxies in the event of a change in applicable indices. Applicable indices are subject to change based upon changes in market circumstances. (C)

3.8 OPERATIONAL MATCHING ORDERS (OMOs)

3.8.1 An OMO is a demand for specific actions on the part of Shippers that are serving Customers with daily measuring devices. All Customers with daily measuring devices, except as specified in the Operational Matching Order section in Paragraph 3 of the RADs, are subject to the Company's issuance of OMOs.

3.8.2 Customers that presently have daily measurement through a charted meter, but not an electronic meter, shall have the option of choosing to be governed by Operational Flow Orders as specified in this Paragraph 3 of the RADS. Customers will be able to exercise this option no more than one time each calendar year by notifying the Company in writing prior to November 1st of each year. Once an election is made, the customer's option will remain in effect until changed.

3.8.3 An OMO will be issued, to the extent possible, with a minimum of eight (8) hours notice to the affected parties. Notice shall be made by the medium most reasonably expected to reach the Customer Proxy with as much notice as reasonably expected to reach the Customer Proxy in a timely manner, including but not limited to: e-mail, facsimile, or Nomination EBB. The notice will include the circumstance that warrant the issuance of the OMO and explain why the actions required are necessary. The notice will be provided via e-mail to the PA PUC.

(C) Indicates Change

3.8 OPERATIONAL MATCHING ORDERS (OMOs) - continued

3.8.4 The Company shall have the authority to direct Customer Proxies to adjust Customer's daily consumption or daily scheduled deliveries (Daily OMO Level) in order that daily scheduled deliveries match Customer's consumption. In order to comply with the OMO, the Shipper may use gas quantities which are: 1) scheduled and delivered on that day to the Company in the same Pipeline Scheduling Point in which the Shipper's customer(s')'s facilities are located; 2) contracted for under Rate SS – Standby Service if the order is pertaining to an under delivery situation; 3) (C) available pursuant to the Rider EBS-Option 1; or 4) additional quantities that may be made available to the Shipper by the Company at its sole discretion including quantities delivered in accordance with the Limitation for Failure of Shipper to Provide Gas to the Company in Customer's Local Market Area section in Paragraph 2 of the RADS.

(C) Indicates Change

3.8.5 When a difference exists between the Daily OMO Level and actual daily OMO compliance quantities delivered, the following charges will be assessed:

(1) A rate equal to three times the highest of the midpoint prices reflected in Platts Gas Daily for the day of the OMO non-compliance and based on pipeline scheduling point applicable indices as specified in the Platts "Gas Daily", Daily Price Survey – Designation by Pipeline Scheduling Point paragraph of Rule 2. Rules Applicable to All Distribution Service in the Rules Applicable to Distribution Service of this tariff. (C)

The charge will be multiplied on the therm difference, except however, the charge will not be assessed if the difference results from the Shipper delivering more than the Daily OMO Level during an OMO that restricts under-deliveries, or from the Shipper delivering less than the Daily OMO Level during an OMO that restricts over-deliveries; and (C)

(2) Payment of all other charges incurred by the Company on the date of the OMO that result from the Shipper's failure to comply with the OMO, including a proportionate share of any pipeline penalties that are incurred by the Company.

(3) In the event midpoint prices referenced in subparagraph (1) above, are not published in Platt Gas Daily for the day of the OMO non-compliance, the highest price paid by the Company on that day shall be used as the index price. (C)

(4) The Company shall update the applicable indices on 60 days' notice to Customer Proxies in the event of a change in applicable indices. Applicable indices are subject to change based upon changes in market circumstances. (C)

3.9 LIMITATIONS ON NOMINATIONS

3.9.1 A Shipper shall not submit a daily gas supply nomination in excess of one hundred percent (100%) of the Customer's currently effective Maximum Daily Quantity except with the Company's prior permission. The Company may reject a nomination to the extent it exceeds one hundred percent (100%) of a Customer's currently effective Maximum Daily Quantity and confirm it at a level equal to the limit if the Shipper did not receive the Company's prior permission. (C)

3.10 LIMITATIONS UPON EXCESS DELIVERIES

3.10.1 The Company reserves the right to limit its receipt of deliveries which are in excess of a Customer's consumption of gas for redelivery to a Customer on any given day ("Excess Deliveries") when such Excess Deliveries may cause the Company to incur penalties for exceeding its allowed daily or total Storage injection capacity of its supplying pipeline or other costs incurred to avoid or mitigate pipeline penalties. The level of the limitation shall be specified electronically by the Company to the Customer Proxy. The Company shall bill a proportionate share of the penalties and other costs that were incurred to avoid or mitigate pipeline penalties to all Customer Proxies whose Shipper fails to comply with the Company's limitation under this Paragraph.

3.11 CONSUMPTION IN EXCESS OF DELIVERIES (UNDER-DELIVERIES)

3.11.1 If, in any billing cycle, the Customer's consumption, plus retainage on the distribution system is greater than the sum of: (a) the quantity of gas delivered to the Company's City Gate by the Shipper for the Customer's account during the billing cycle; plus (b) if the Customer Proxy subscribes to EBS-Option 1, access to banked gas quantities as permitted under EBS-Option 1; plus (c) bank transfers performed for that cycle, then such use shall be considered imbalance gas sold by the Company to the Customer Proxy.

(C) Indicates Change

4.7.4 Aggregation Imbalances

4.7.4.1 There shall be an annual reconciliation and cash-out of the difference between the actual consumption of each Choice Aggregation Nomination Group and the NGS's deliveries on behalf of each Choice Aggregation Nomination Group. The reconciliation and cash-out amount shall be calculated annually following each July billing cycle.

4.7.4.2 If the actual consumption of the Choice Aggregation Nomination Group is more than the NGS's deliveries on behalf of that group, the NGS must purchase the deficient quantity from the Company at the average price during the reconciliation period as reported in Platt's Inside FERC's Gas Market Report as published for the first of each month under the column heading "Index" for "Columbia Gas, App", adjusted for Columbia Gas (C)
Transmission, LLC's FTS retainage and commodity charge.

4.7.4.3 Likewise, if the actual consumption of the Choice Aggregation Nomination Group is less than the NGS's deliveries on behalf of that group, the Company shall purchase the excess quantity from the NGS at the average price during the reconciliation period as reported in Platt's Inside FERC's (C)
Gas Market Report as published for the first of each month under the column heading "Index" for "Columbia Gas, App", adjusted for Columbia Gas Transmission, LLC's FTS retainage and commodity charge.

4.7.4.4 In the event that an NGS's Choice Aggregation Nomination Group decreases by 10% or 1,000 Customers, the Company may elect to Cash Out that NGS at such time. The purchase or sale price of the difference between the actual consumption of the Choice Aggregation Nomination Group and the NGS's deliveries on behalf of that Choice Aggregation Nomination Group shall be the weighted average commodity cost of gas, defined as the quotient of: (1) the total commodity cost of gas purchases, including transmission pipeline transportation and fuel retention, as recorded on the Company's financial statements between the preceding July 1 and the month in which the Cash Out occurs, divided by (2) tariff sales for the same period.

4.7.5 Assignment. The NGS shall only assign the Choice Customer Group to another NGS with the prior written consent of the Company. The Company shall not unreasonably withhold its consent; however, the Company may condition the assignment upon the fulfillment of reasonable requirements including but not limited to: a demonstration that the agreement between the NGS and the Customer allows an assignment or that the customer had otherwise consented to the assignment; requiring the assignee to take assignment of any gas bank balance existing at the time of the assignment; or requiring the assignee to take assignment of any financial obligation existing at the time of the assignment.

(C) Indicates Change

The NGS agrees, if required by the Company, to make daily deliveries through the assigned capacity without regard to the loss of Customers. The NGS must accept the assignment or release of either Columbia Gas Transmission, LLC capacity and Columbia Gulf Transmission, LLC capacity or Columbia Gas Transmission, LLC capacity only. (C)

The assignment or release of Columbia Gas Transmission, LLC FTS capacity shall be equal to the Choice Primary FTS Daily Capacity Requirement. (C)

The Columbia Gulf Transmission, LLC Rate Schedule FTS-1 capacity to be assigned or released shall be based upon the assigned Rate FTS capacity increased for applicable pipeline fuel. The Company shall release this capacity, on a recallable basis, utilizing the appropriate pipeline company electronic bulletin boards and the NGS shall execute the service agreements so generated by the pipelines prior to the end of the month to enable the NGS to nominate gas supplies under the service agreements for the following month. (C)

Should the Choice Aggregation Nomination Group's quantity increase in subsequent months resulting in the need for additional capacity to be assigned to the NGS, the Company shall utilize the process described above to assign the additional quantities to the NGS with each assignment being for a one-year period.

4.8.3.1 Other Primary FTS Option. The NGS may have the option to provide some or all Primary FTS capacity from some other source for a period of one year. This capacity option shall be made available to an NGS to the extent that the cumulative Other Primary FTS Daily Capacity Requirements (Other Primary FTS) of all NGSs requesting this option does not exceed the Additional Capacity Resource Requirement (ACRR).

An NGS providing Other Primary FTS is required to obtain and maintain capacity resources sufficient to deliver natural gas equal to its Choice Primary FTS Daily Capacity Requirements each day during the effective period of its capacity option election.

The cumulative Other Primary FTS of NGSs may not exceed the ACRR the Company may require in any year.

The ACRR for any year shall be the additional capacity, if any, which is required to meet design day requirements in excess of the Company's available design day capacity, as set forth in its annual 1307(f) filing, for the immediately following November through October period.

(C) Indicates Change

4.8.4 Subject to the Company's obligations concerning its Acquisition Process for New and Renewed Capacity under the Joint Petition for Settlement of Restructuring Filing in Docket No. R-00994781, should the Company decide to terminate its capacity on Columbia Gas Transmission, LLC or Columbia Gulf Transmission, LLC, any capacity (C) assignment will terminate no later than the end of the term of the Company's service agreement with the pipeline. It shall be the responsibility of the NGS to acquire Primary FTS subsequent to such termination.

4.8.5 The NGS will at all times be responsible for operating the assigned capacity consistent with the terms and conditions set forth in the tariffs of the Company and the applicable pipeline companies.

4.8.6 Insufficient Capacity. The Company may require that the NGS verify that the Other Primary FTS contract rights exist. The NGS shall comply with the Company's request for verification. The failure or inability of the Company to verify the existence of such contract rights shall not relieve the NGS from any liability for failing to deliver gas, or subject the Company to any liability resulting from the NGS's failure to deliver. The Company may require the NGS to demonstrate in writing, and the NGS shall have the obligation to demonstrate in writing that: (a) The NGS has under contract sufficient firm capacity; AND (b) the NGS utilized such capacity to schedule sufficient supplies at the delivery points specified in the NGS Choice Distribution Aggregation Agreement to meet the needs of Customers served under these Rules Applicable to Distribution Service, and the pipeline confirmed such schedule to said delivery points. Failure to demonstrate that sufficient Other Primary FTS capacity was held shall subject the NGS to bear its respective share of any and all costs incurred by the Company as a result of the NGS's failure. Should an NGS fail to demonstrate that it held adequate capacity on a day when an OFO was in effect, the NGS shall be subject to the penalty provision described in Paragraph 4.11 of these Rules Applicable to Distribution Service, and the fees set forth in Paragraph 4.12. On any and all days in which the NGS's delivery of gas does not match the total requirements of all of the NGS's Choice Aggregation Nomination Groups, the NGS shall pay the Company the fees set forth in Paragraph 4.12 of these Rules Applicable to Distribution Service.

(C) Indicates Change

4.9.4 Commencement of Natural Gas Supply Service. For Customers which were submitted to the Choice EBB by the 15th of the current month, the NGS is obligated to begin flowing gas in the amount of its Choice Daily Delivery Requirement on the first day of the following month. For Customers which were submitted to the Choice EBB after the 15th of the current month, the NGS is obligation to begin flowing gas on the first day of the second following month. During the interim period, the Customer shall be served by his existing Natural Gas Provider.

4.9.5 Delivery Requirements. NGSs must make firm deliveries to the Company on any and all days which shall meet the Choice Daily Delivery Requirements of each of the NGS's Choice Aggregation Nomination Groups. The NGS must deliver the Choice Daily Delivery Requirement, which must be firm supply for the months of November through March, and which must be of a quality acceptable to the Company, and the NGS must have made, or cause to be made, arrangements by which such gas supply can be transported directly to the Company's system in the Local Market Area in which the Customer is located on a firm basis, unless otherwise permitted by the Company in writing.

In order to facilitate compliance with upstream pipeline restrictions, and to maintain operational integrity, it may be necessary from time to time for the Company to require Choice Natural Gas Suppliers to schedule natural gas supplies to the Company from multiple transmission pipeline delivery points or to such other delivery points as designated by the Company. (C)

4.9.6 Insufficient Supplies. In the event that the NGS fails to deliver its Choice Daily Delivery Requirement to the Company, the Company shall have the right to require the NGS to demonstrate, and the NGS shall have the obligation to demonstrate that the NGS scheduled sufficient supplies at the delivery points specified in the NGS Choice Distribution Aggregation Agreement to meet its Choice Daily Delivery Requirements for each of its Choice Aggregation Nomination Groups, and that the pipeline confirmed such schedule to said delivery points. Failure to demonstrate that the Choice Daily Delivery Requirement was made to any market or interstate pipeline interconnection shall subject the NGS to bear its respective share of any and all costs incurred by the Company as a result of the NGS's failure. Should an NGS fail to demonstrate that it delivered its Choice Daily Delivery Requirement for each of its Choice Aggregation Nomination Groups on a day when an OFO was in effect, the NGS shall be subject to the penalty provision described in these Rules Applicable to Distribution Service Paragraph 4.11, and the fees set forth in Paragraph 4.12. On any and all days in which the NGS's delivery of gas does not match the Choice Daily Delivery Requirement of each of the NGS's Choice Aggregation Nomination Group, the NGS shall pay the Company the fees set forth in Paragraph 4.12 herein.

4.9.7 Adjustment to Choice Daily Delivery Requirements. The Company, at its discretion, may compare actual and weather normalized consumption immediately following the winter period. The Company may require any NGS to adjust the NGS's Choice Daily Delivery Requirements during the months of May, and June for the difference between the Choice Aggregation Nomination Group's actual consumption and weather normalized consumption.

4.10 OPERATIONAL REQUIREMENTS

4.10.1 In order to provide those customers who are located in Local Market Areas served by an interstate pipeline other than Columbia Gas Transmission, LLC a fair opportunity to obtain choice of an NGS, the Company may implement one of the following procedures: (C)

4.10.1.1 The Company may require all NGSs under this Schedule to accept assignment of capacity on interstate pipelines other than Columbia Gas Transmission, LLC in an amount which is proportional to the number of customers served by the NGS divided by all customers eligible for Choice Service. (C)

(C) Indicates Change

4.10.1.2 The Company may retain, renew or replace the interstate pipeline capacity on the interstate pipeline other than Columbia Gas Transmission, LLC and require NGSs under this Schedule, if authorized by FERC rules or orders, to deliver a portion of supplies required by this Schedule into such capacity with such proportion determined as in Paragraph 4.10.1.1, or (C)

4.10.1.3 The Company may make a payment to one or more NGSs to accept assignment of such capacity and use such capacity to meet the requirements of customers. Such payment shall be recoverable by the Company from customers. To the extent that such payment does not increase sales rates over levels which would be charged if the Company retained such capacity, it shall be recovered under the Purchased Gas Cost Rider from sales customers and customers subject to this Schedule. Any excess over such amount shall be recoverable under Rider CC. (C)

4.10.2 The "Calculation of Demand Cost for Customers Electing Choice Service" provisions of the Purchased Gas Cost Rider shall be deemed modified to the extent necessary consistent with the Company's implementation of one of the foregoing procedures.

4.10.3 In the event an OFO limits deliveries to the Company via FTS capacity below the level of any capacity assigned, the unused FTS capacity may be reassigned by the assignee for the duration of the OFO event. The NGS shall be required, prior to the end of the year for which the capacity was assigned, to deliver additional quantities via ITS equal to the quantities not delivered via FTS capacity during the OFO event.

4.11 OPERATIONAL FLOW ORDERS (OFOs)

4.11.1 All Choice NGSs are subject to the Company's issuance of OFOs. The Company will have the authority to direct NGSs to adjust daily scheduled quantities to a specified level. Generally, during peak design day conditions, this specified level will be equal to the Choice Daily Delivery Requirement. Should conditions be greater or less than peak design day conditions, the specified level of the OFO may be greater or less than the Choice Daily Delivery Requirement.

4.11.2 When a difference between the daily OFO quantity and actual daily scheduled deliveries to the Company exist, the following charges will be assessed:

(1) The therm difference will be multiplied by a rate equal to three times the highest of the midpoint prices reflected in Platts Gas Daily for the day of the OFO non-compliance and based on pipeline scheduling point applicable indices as specified in the Platts "Gas Daily", Daily Price Survey – Designation by Pipeline Scheduling Point paragraph of Rule 2. Rules Applicable to All Distribution Service in the Rules Applicable to Distribution Service of this tariff; and, (C)

(2) The payment of all other charges incurred by the Company on the date of the OFO that results from the NGS's failure to comply with the OFO including a proportionate share of any pipeline penalties that are incurred by the Company.

(3) In the event midpoint prices referenced in subparagraph (1) above, are not published in Platts Gas Daily for the day of the OFO non-compliance, the highest price paid by the Company on that day shall be used as the index price. (C)

(C) Indicates Change

4.12 RATES

4.12.1 Customers served under Rate Schedules RDS and SCD will be billed all applicable charges under the rate schedule. The Customer, or Customer's NGS, shall pay directly to the interstate pipelines the charges for any assigned pipeline capacity.

4.12.2 For NGSs providing service under these Rules Applicable to Distribution Service, the following fees shall be assessed to the NGS:

NGS One-time Application Fee: $390.00

4.12.3 In addition the following billing fees will apply:

Billed Account Adjustments: $ 1,000.00 processing fee per adjustment plus;
$ 1.00 per adjusted account

4.12.4 Delivered Quantities. All quantities billed to Customers under these Rules Applicable to Distribution Service shall be considered actual quantities delivered, whether the meter reading is an actual or a calculated reading.

4.12.5 Failure to deliver the Choice Daily Delivery Requirement for any Choice Aggregation Nomination Group shall subject the NGS to a charge on the difference between the Choice Daily Delivery Requirement and the actual daily deliveries. The charge will be equal to the therm difference multiplied by a rate per therm that is three times the highest of the midpoint prices reflected in Platts Gas Daily for each day the NGS did not meet its Choice Daily Delivery Requirement and based on pipeline scheduling point applicable indices as specified in the Platts "Gas Daily", Daily Price Survey – Designation by Pipeline Scheduling Point paragraph of Rule 2. Rules Applicable to All Distribution Service in the Rules Applicable to Distribution Service of this tariff. (C)

In the event midpoint prices referenced in the above paragraph are not published in Platts Gas Daily for the day when the Choice Daily Delivery Requirement has not been met, the highest price paid by the Company on that day shall be used as the index price. (C)

In addition the NGS will be responsible for the payment of all other charges or costs incurred by the Company that result from the NGS's failure to deliver as required, including a proportionate share of any pipeline penalties incurred by the Company.

The NGS will also be required to deliver the remaining portion of its Choice Aggregation Nomination Group's estimated normalized usage via ITS in the summer months defined as April through October, unless the Company authorizes a lower or higher level of deliveries via ITS. (C)

(C) Indicates Change

4.13 COMPANY BILLING OF NGS NATURAL GAS SUPPLY SERVICES – continued

4.13.3.2 Billing Option 2: Company Billing Service. The NGS elects to have the Company bill the Customers for the NGS's Natural Gas Supply Services charges. The NGS understands that the Company shall provide billing services pursuant to the requirements of its tariffs. The Company shall purchase the accounts receivable of any NGS that elects this billing option pursuant to the Voluntary Purchase of Receivables Program paragraph in these Rules Applicable to Distribution Service.

4.13.3.2.1 The Company shall provide the NGS with meter reading information and other reports in the Company's standard printed or electronic format on a monthly basis corresponding to the Company's Billing Cycle. The NGS shall provide the Company with all required billing determinants as indicated on the Company's "NGS Rate Statement" and other information that may be necessary for Customer billing as determined by the Company. The NGS shall provide said billing determinants in the standard printed or electronic format specified by the Company. The NGS shall provide the Company with said billing determinants no later than the 20th of the month prior to the effective Billing Cycle, by supplying a new NGS Rate Statement. If the 20th of the month falls on a weekend or holiday, the billing determinates shall be due on the last business day prior to the 20th of the month. (C)

(C) Indicates Change

4.14.2 Slamming Complaints. When a Customer contacts the Company after the 10 day waiting period and alleges that their NGS has been changed without their consent, the Company shall consider the matter a Customer-registered dispute and investigate and respond to the dispute consistent with the requirements found in §§56.151 and 56.152. A Customer who has had an NGS changed without having consented to the change shall be switched back to the previous Natural Gas Provider. Any charges involved in the switch back to the previous Natural Gas Provider shall be the responsibility of the NGS that initiated the change without the Customer's consent. PA. P.U.C. Docket No. M-00991249F006.

4.15 INDEMNIFICATION

4.15.1 The NGS shall indemnify, save harmless and at Company's option, defend Company from and against any and all losses, claims, demands, damages, costs (including, without limitation, reasonable attorney's fees), expenses, liabilities, proceedings, suits, actions, restrictions, injunctions, fines, judgments, penalties and assessments which Company may suffer for, on account of, by reason of or in connection with service provided under these Rules Applicable to Distribution Service, and in connection with any bodily injury, including death to any person or persons (including, without limitation, the NGS's employees) or any damage to or destruction of any property, including without limitation, loss of use thereof, arising out of, in any manner connected with or resulting from the gas or services furnished by the NGS under these Rules Applicable to Distribution Service.

4.16 TERMINATION OF AN NGS's PARTICIPATION UNDER THIS SCHEDULE

4.16.1 Should any NGS elect or be required to discontinue serving Customers on the Company's distribution system under Customer Choice, the NGS shall: a) provide all notices required under 66 Pa. C.S. Section 2207(i); b) reassign any capacity originally assigned to it by the Company back to the Company or assign to the Company any new, replacement and/or alternate capacity it acquired; or c) assign the capacity identified in "b)" to another NGS that has accepted assignment of the first "NGS's" Customers; and d) the NGS shall continue its obligation to maintain its financial security instrument until it has satisfied all of its outstanding claims of the Company Upon an NGS's discontinuation of Natural Gas Supply Services, the Company may offset any and all amounts owed to it by the NGS against any and all amounts owed by the Company to the NGS, including without limitation, charges for imbalance gas sold by the Company, out of period adjustments to the NGS's account, amounts owed to the NGS for bank balances, amounts owed to the NGS for accounts receivable collected by the Company, and amounts owed to the Company for OFO charges, etc. (C)

(C) Indicates Change

Appendix E

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2016-2529660
Office of Consumer Advocate	:	C-2016-2535301
Office of Small Business Advocate	:	C-2016-2538051
Columbia Industrial Intervenors	:	C-2016-2541753
Pennsylvania State University	:	C-2016-2541623
Ralph Miller	:	C-2016-2538611
Michael Pikus	:	C-2016-2538843
Richard Collins	:	C-2016-2547479
James Testrake	:	C-2016-2555931
	:	
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

STATEMENT OF COLUMBIA GAS OF PENNSYLVANIA, INC.
IN SUPPORT OF THE JOINT PETITION FOR SETTLEMENT

TO ADMINISTRATIVE LAW JUDGE KATRINA L. DUNDERDALE:

I. INTRODUCTION

Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") hereby submits this Statement in Support of the Joint Petition for Settlement ("Settlement") entered into among Columbia, the Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), Columbia Industrial Intervenors ("CII"), Dominion Retail, Inc. ("Dominion"), Shipley Energy Company ("Shipley"), Interstate Gas Supply, Inc. ("IGS") and AMERIGreen Energy ("AMERIGreen"),[1] the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), Community Action Association of Pennsylvania ("CAAP"), the Pennsylvania State University ("PSU") and Direct Energy Business, LLC, Direct Energy Services, LLC, and Direct Energy Business Marketing, LLC (collectively, "Direct

[1] Dominion, Shipley, IGS and AMERIGreen will be referred to collectively as the "NGS Parties".

Energy") (hereinafter collectively referred to as the "Joint Petitioners" or "Parties"), parties to the above-captioned proceedings. Columbia respectfully requests that Administrative Law Judge Katrina L. Dunderdale (the "ALJ") recommend that the Commission approve the Settlement, including the terms and conditions thereof, without modification.

The Settlement, if approved, will resolve all issues raised by the Joint Petitioners in this proceeding. The settled issues include revenue requirement, revenue allocation, rate design, universal service matters, programs to expand the availability of gas service, natural gas supplier issues and other issues. The Settlement is in the public interest, balancing the interests of Columbia, its customers, and the Joint Petitioners. Accordingly, it should be approved without modification.

The Settlement was achieved only after a comprehensive investigation of the basis of Columbia's claims and those advanced by the Joint Petitioners, as a whole. In addition to informal discovery, Columbia responded to 429 formal discovery requests (many of which had multiple subparts). The active parties filed multiple rounds of testimony and accompanying exhibits, including Columbia's direct, rebuttal, and surrebuttal testimony, and other parties' direct, rebuttal, and surrebuttal testimony. Columbia and PSU also filed rejoinder testimony outlines. Moreover, the active parties participated in numerous settlement discussions and formal negotiations, which ultimately led to the Settlement.

Finally, the active parties in this proceeding, and their counsel and experts, have considerable experience in rate proceedings. Their knowledge, experience, and ability to evaluate the strengths and weaknesses of their litigation positions provided a strong foundation upon which to build a consensus on the settled issues. All of the active parties to this proceeding, with the exception of CAAP and Direct Energy, were active parties in Columbia's last base rate proceeding at Docket No. R-2015-2468056, and were therefore familiar with many of the issues that are addressed in this case.

The Settlement reflects a carefully balanced compromise of the interests of the Joint Petitioners to this proceeding. For these reasons and the reasons set forth below, the Settlement is just and reasonable and should be approved.

II. <u>SPECIFIC SETTLEMENT TERMS</u>

A. REVENUE REQUIREMENT

The Settlement provides for rates designed to produce an annual increase in operating revenues of $35 million based upon the pro forma level of operations for the twelve months ended December 31, 2017. (Settlement ¶ 24.) The $35 million annual increase in tariff rates will go into effect on December 19, 2016, which is the effective date of rates under the Commission's April 21, 2016 suspension order. (Settlement ¶ 36.) The Settlement increase is approximately 63% of Columbia's original request of $55.3 million. (Columbia Exhibit 102, Sch. 3, p. 3.) The $35 million annual increase, although less than that requested by the Company, will enable the Company to continue to provide safe and reliable service to its customers.

As explained by Mark Kempic, President of Columbia, one primary reason in support of the revenue increase is to provide the Company with an opportunity to earn a return on the significant capital investments made to its distribution system. (Columbia Statement No. 1, pp. 6-9.) Columbia has made, and continues to make, substantial capital investments in its system as part of the Company's accelerated pipeline replacement program. (Columbia Statement No. 1, pp. 6-9.) Since Columbia started its accelerated pipeline replacement program in 2007, Columbia has replaced over 744 miles of cast iron and bare steel ("CIBS") pipe. (Columbia Statement No. 1, p. 8.) In 2015 alone, Columbia replaced over 97 miles of CIBS pipe. (Columbia Statement No. 1, p. 8.)

Columbia's actual investment in replacement pipe has exceeded the Company's projections. Columbia forecasted that its 2015 capital budget for the replacement of CIBS pipe would be $145 million. Columbia's 2015 actual investment for replacement pipe was $152 million. Columbia intends to continue its accelerated level of investment in replacement pipe. In Columbia's 2015 rate case at Docket No. R-2015-2468056, Columbia projected that its 2016 capital budget for the replacement of CIBS pipe would be $147 million. The Company's "age and condition" capital budget for 2016 is now $162 million. (Columbia Statement No. 1, p. 9.) Columbia plans to continue to increase its capital expenditures in the 2016 to 2020 timeframe, with a planned spending program ranging between $157 and $210 million budgeted annually for pipeline replacement over the 5-year period. (Standard Data request GAS-ROR-014.)

In addition to capital costs associated with Columbia's accelerated pipeline replacement effort, the Company is incurring operating and maintenance ("O&M") costs associated with enhancing pipeline safety on its system. These costs further contribute to the level of the revenue increase agreed upon in the Settlement of this case. (Columbia Statement No. 7, pp. 35-40.) The Company's pipeline safety initiatives include: a formal employee training and qualification program to address the DIMP and system risks associated with human error in the field; construction and operation of a new training center that will provide the facilities needed to conduct classroom and enhanced hands on employee training; the addition of frontline leader positions to manage the current and anticipated entry of new employees to the Company's workforce; the addition of four damage prevention coordinators; and a program to address the risk of field-assembled riser failures. (Columbia Statement No. 7, pp. 37-40.)

In order to provide ongoing information concerning Columbia's capital investments, Columbia has agreed that, on or before April 1, 2017, Columbia will provide the Commission's Bureau of Technical Utility Services ("TUS"), 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, 2016. (Settlement ¶ 32.) On or before April 1, 2018, Columbia will update Exhibit No. 108, Schedule 1 filed in this proceeding for the twelve months ending December 31, 2017. (Settlement ¶ 32.) Also, as part of the Company'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, 2017. (Settlement ¶ 32.) However, and as described more fully below, 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.

In this proceeding, Columbia, I&E and OCA presented testimony on Columbia's overall revenue requirement and related issues. I&E suggested several adjustments to the Company's O&M expenses. While the OCA offered no individual adjustments to Columbia's O&M expenses, OCA did take issue with the Company's use of fully forecasted rate year ("FFRY") year-end balances in order to determine its rate base and the Company's calculation of depreciation expense. The Settlement revenue increase of $35 million annually reflects a reasonable compromise of Joint Petitioners' positions in this proceeding. The amount of the increase falls within the range of outcomes bounded

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by Columbia's proposed increase and the revenue requirements contained in the direct testimonies of I&E and OCA. Columbia notes that in its rebuttal testimony, it took issue with virtually all of the recommendations presented by I&E and the OCA. The Joint Petitioners, while supporting their revenue requirement positions for litigation purposes, recognized that the Commission likely would have accepted certain adjustments proposed by Joint Petitioners, but would not have accepted all of the adjustments.

Under the Settlement, with only a few select exceptions further explained herein, the settlement revenue requirement is a "black box" amount. Under a "black box" settlement, parties do not specifically identify revenues, expenses and return that are allowed or disallowed. Columbia believes that "black box" settlements facilitate agreements, as parties are not required to identify a specific return on equity or identify specific revenues and/or expenses that are allowed or disallowed.

Considering the Settlement as a whole, Columbia believes that the revenue requirement is reasonable and will provide the Company with the additional revenues that are necessary to provide reliable service to customers. In addition, Columbia believes that the Settlement appropriately balances the need of the Company to have an opportunity to earn a reasonable rate of return with its customers' need for reasonable rates.

1. Distribution System Improvement Charge ("DSIC")

The Commission approved Columbia's DSIC by Order entered May 22, 2014, at Docket No. P-2012-2338282. With the DSIC, plant additions not included in base rates may be reflected in the DSIC calculation. Therefore, for future DSIC purposes, it is necessary to establish relevant plant balances for the Company in this proceeding. The

Settlement provides that, following the effective date of rates in this proceeding, Columbia will be eligible to include plant additions in the DSIC once eligible account balances exceed the levels projected by Columbia at December 31, 2017. (Settlement ¶ 25.) The Joint Petitioners agree that this 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 fully-projected future test year filing. (Settlement ¶ 25.)

The Settlement also provides that, 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 Columbia 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). (Settlement ¶ 26.)[2]

2. Tax Repair Allowance and Mixed Service Cost Normalization Treatment

In 2008, Columbia sought and obtained permission from the Internal Revenue Service to change its definition of "unit of property" for tax purposes. This enabled Columbia to deduct certain expenditures on its tax return rather than capitalize them and resulted in a tax refund of $37,487,634 for Columbia's customers. As agreed in the settlement of Columbia's 2010 rate case at Docket No. R-2009-2149262, a refund of the $37,487,634 is being made to customers, which reflects the cash benefit received in

[2] In its Order entered December 10, 2014, approving the settlement in Columbia's 2014 base rate proceeding at Docket No. R-2014-2406274, the Commission stated that base rate settlements must stipulate a Return on Equity ("ROE") for DSIC purposes. (Order at p. 15.) The Commission noted that one option is to stipulate that the ROE for DSIC purposes will track the equity return rate from the most recent Commission staff Quarterly Earnings Report.

2009 for the tax year 2008 method change. (Columbia Statement No. 10, p. 4.) As of December 31, 2014, a total of $35,442,920 was amortized, as agreed to in Columbia's 2012 rate case at Docket No. R-2012-2321748, and an additional $2,044,714 is being amortized through the period ended December 31, 2016, as agreed to in Columbia's 2014 rate case at Docket No. R-2014-2406274. The Settlement in Columbia's 2015 base rate case specified that there would be a one year amortization of the remaining $681,571 balance in 2016. *Pennsylvania Public Utility Commission, et al. v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2015-2468056 (Opinion and Order entered December 3, 2015). This case reflects the remaining $681,571 as of December 31, 2015 being amortized over 12 months in the Future Test Year ("FTY"), which represents a full amortization of the refund by the beginning of the FFRY. (Columbia Statement No. 10, p. 4.)

Under the Settlement, Columbia will continue to use normalization accounting with respect to the benefits of the tax repairs deduction. The Settlement acknowledges that Columbia has completed the amortization of the $37.4 million tax refund previously received by Columbia. (Settlement ¶ 27.) The Settlement also continues prior agreements that subsequent changes in the refund amount, above or below the $37.4 million, shall be reflected in accumulated deferred income taxes to be created under the normalization method of accounting. (Settlement ¶ 27.) Because this provision continues the previously-approved rate treatment of this refund, it is in the public interest and should be approved.

Also, the Joint Petitioners also have agreed that Columbia will continue to use normalization accounting with respect to the tax treatment of Internal Revenue Code Section 263A mixed service costs ("MSC"). (Settlement ¶ 28.) This is similar to the treatment of book versus tax timing differences for the repairs deduction. (Columbia Statement No. 10, p. 4.) This treatment was established in the settlement of Columbia's 2012 rate case at Docket No. R-2012-2321748, and was unopposed in this proceeding. The Parties have agreed that such treatment should continue.

3. Amortizations

The settlement in Columbia's 2012 rate case established an amortization for non-labor costs associated with the NiSource NiFiT project.[3] Per the settlement approved at Docket No. R-2012-2321748, Columbia was allowed amortization recovery of the then-estimated non-labor NiFit expenses over a four-year period. (Columbia Statement No. 4, p. 23.) Columbia's 2015 base rate case settlement provided for a three-year amortization of the remaining unamortized balance of $1,260,764, beginning on December 18, 2015. The Settlement in this case continues amortization of the $1,260,764 for NiFit costs over the three-year period. (Settlement ¶ 29(i).)

The Settlement specifies the continued amortization of costs related to Blackhawk Storage. This amortization was established in Columbia's 2008 rate case settlement at Docket No. R-2008-2011621 and will continue. (Settlement ¶ 29(ii).) No party objected to the Company's inclusion of this amortization amount in its rate filing.

These amortizations are continuations of previously-approved amortizations, and were unopposed by any party. The amortizations are in the public interest and should be approved.

4. Other Post-Employment Benefits ("OPEB") Expense

The Settlement includes provisions concerning accounting for Columbia's ongoing contributions to trusts for OPEBs which were established in the settlement of

[3] NiFiT is a project designed to upgrade financial processes and information systems across all of the NiSource companies, including Columbia.

Columbia's 2012 base rate case at Docket No. R-2012-2321748. (Columbia Statement No. 4, pp. 37-38.) These provisions were unopposed by any party, and are in the public interest, because they confirm the ongoing treatment of OPEB expense. Columbia will 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 O&M would be deferred and recognized as a regulatory asset or liability. To the extent the cumulative balance recorded commencing with the effective date of rates reflects a regulatory asset, such amount will be collected from customers in the next rate proceeding over a period to be determined in that rate proceeding. In addition, to the extent the cumulative balance recorded commencing with the effective date of rates reflects a regulatory liability, there will be no amortization of the (non-cash) negative expense, and the cumulative balance will continue to be maintained. (Settlement ¶ 30.) The Settlement provides that 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 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. (Settlement ¶ 31.)

Pursuant to the Opinion and Order entered on May 24, 2012, at Docket No. P-2011-2275383, Columbia deferred, for accounting and financial reporting purposes, the one-time expense of $903,131 associated with its allocated share of NiSource Corporate Services Company's ("NCSC") OPEB regulatory asset resulting from NCSC's transition from cash basis to accrual. In the settlement of the 2012 Columbia base rate case at

Docket No. R-2012-2321748, Columbia was allowed to recover the total deferred amount of $903,131 over a ten-year period that began on July 1, 2013. This Settlement continues the ten-year amortization established in the 2012 rate proceeding. (Settlement ¶ 29(iii).)

5. Future Debt Issuances

I&E proposed that certain information be provided to the statutory parties following the actual issuances of debt projected for the FTY and Fully Projected Future Test Year ("FPFTY"). Under the Settlement, Columbia agrees that, for all future debt issuances during the twelve-month periods ending December 31, 2016 and December 31, 2017, Columbia will provide to TUS, I&E, OCA and OSBA, within 60 days of issuance, all loan documentation filed with the Commission in compliance with orders in filings submitted by Columbia pursuant to Chapter 19 of the Public Utility Code. In addition, Columbia will preserve and provide to I&E, OCA and OSBA as a part of its next base rate case the following: (1) all documentation supporting debt issued between this base rate case and the next base rate case; and (2) for each issuance, the prevailing yield on U.S. utility bonds as reported by Bloomberg Finance L.P. for companies with a credit risk profile equivalent to that of NiSource Finance Corp. (Settlement ¶ 33.)

B. REVENUE ALLOCATION AND RATE DESIGN

Appendices "A" and "B" to the Settlement set forth the agreed-to revenue allocation and rate design to the classes, respectively. (Settlement ¶ 40.) As described below, these items were the subject of extensive litigation and negotiation, and reflect a compromise of the positions of all the Parties to this proceeding. The Settlement strikes a balance that is in the best interest of all of Columbia's customers, and should be approved.

1. Revenue Allocation

As in many base rate cases, the revenue allocation issues were among the most contentious issues in this proceeding. The Joint Petitioners proposed a variety of class cost of service studies and cost allocation methodologies. Moreover, even to the extent certain Joint Petitioners agreed on the basic overall methodology, *i.e.* the Design Day demand allocation versus the Peak & Average methodology, these Joint Petitioners still disagreed on how to allocate certain other costs to the different rate classes, as well as how much movement toward cost of service was appropriate. Despite the fact that the Joint Petitioners were not able to agree on a specific class "cost of service" in the Settlement, they were able to agree to a revenue allocation that is within the range of revenue allocations proposed by the Joint Petitioners in this proceeding, and Columbia believes that this revenue allocation meets the "cost of service" standards adopted by the Courts and the Commission.

All Parties supported their respective cost of service studies for litigation purposes. However, the Parties were willing to compromise in order to achieve a settlement of the revenue allocation issues. Therefore, the revenue allocation set forth in the Settlement is not based upon a specific agreed-to formulaic approach. Moreover, the Settlement rates are not based upon any specific cost of service study results. Instead, the Settlement reflects a compromise of the Parties' revenue allocation and rate design proposals. (Settlement Appendices "A" and "B".) The resulting class increases, as compared to the Company's as-filed increases, are as follows:

Customer Group	As Filed	Percentage of Proposed Increase[4]	As Settled	Percentage of Settled Increase
Residential (RS/RDS)	$43,083,078	78.15%	$25,900,000	74.01%
Small General Service1 (SGSS1/SGDS1/SCD1)	$4,269,365	7.75%	$2,915,774	8.33%[5]
Small General Service2 (SGSS2/SGD2/SCD2)	$3,750,418	6.80%	$3,284,226	9.38%
Small Distribution Service (SDS/LGSS)	$1,845,302	3.35%	$1,800,000	5.14%
Large Distribution Service (LDS/LGSS)	$2,174,669	3.95%	$1,100,000	3.14%
Mainline Distribution Service (MLDS/NSS)	$0	0.00%	$0	0.00%
Total	$55,122,832	100.00%	$35,000,000	100.00%

As noted above, the revenue allocation under the Settlement represents a compromise and falls within the range of litigation positions of the Joint Petitioners. Columbia notes that, because of the disagreement over cost allocation studies and the "black box" nature of the Settlement, it is not possible to precisely calculate the extent to which the Settlement moves rates closer to cost of service for all Joint Petitioners. However, Columbia believes that the Settlement achieves progress in the movement toward cost-based rates for all customer classes.

4 Columbia St. No. 3, p. 19; Exh. 103, Sch. 8, p. 5.
5 For purposes of Appendix "A" to the Settlement, the total increase agreed to for the SGS class as a whole is $6,200,000.

2. Rate Design

a. Residential Rate Design

In this proceeding, Columbia proposed to increase the customer charge for residential customers from $16.75 to $19.51. (Columbia Statement No. 3, p. 25.) This increase was opposed by OCA, I&E and CAAP. (OCA Statement No. 3, p. 34; I&E Statement No. 3, p. 20; CAPP Statement No. 1, p. 3.) As part of the Settlement, the Joint Petitioners have agreed that the residential customer charge will remain at the current rate of $16.75/month. (Settlement ¶ 38.)

b. Commercial and Industrial Rate Design

In this proceeding, Columbia proposed to keep the customer charge for small commercial and industrial customers under Rates Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD"), and Small General Distribution Service ("SGDS") using less than 6,440 therms annually at the current $21.25. (Columbia Statement No. 3, p. 32.) In addition, the Company proposed that the customer charge for customers under these rate schedules that use more than 6,440 therms annually be increased to $57.46. (Columbia Statement No. 3, p. 26.)

The OSBA and I&E objected to the proposed increase to the customer charge for customers under Rates SGSS, SCD, and SGDS using more than 6,440 therms annually. Instead, OSBA recommended that the customer charge for these customers remain at the current $48.00.[6] (OSBA Statement No. 1, p. 29.) I&E recommended that the customer charge for these customers be increased to $56.04. (I&E Statement No. 3, p. 22.)

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[6] The OSBA recommended a customer charge for the smaller-sized customers of $25.00/ month, but no increase to the current customer charges for the entire SGS/SGDS class if the Commission determined that there should not be a customer component of mains included in the customer charge. (OSBA St. No. 1, pp. 29-30).

Under the Settlement, the Joint Petitioners have agreed that the customer charge shall remain at the current $21.25 per month for customers under Rates SGSS, SCD, and SGDS using up to 6,440 therms annually. (Settlement ¶ 39.) In addition, the Joint Petitioners have agreed that the customer charge shall remain at the current $48.00 per month for customers under Rates SGSS, SCD, and SGDS using more than 6,440 therms annually. (Settlement ¶ 39.) This is consistent with Columbia's proposal for customers using less than 6,440 therms annually and OSBA's proposal for customers using more than 6,440 therms annually, and should be approved. (Columbia Statement No. 3, p. 26; OSBA Statement No. 1, p. 29.)

In this proceeding, Columbia initially proposed a 3.95% rate increase for the Large Distribution Service ("LDS")/Large General Sales Service ("LGSS") class. (Columbia Statement No. 3, p. 20.) Witnesses for CII and PSU testified that the LDS rate increase, as proposed, was burdensome, in part because the LDS rate class includes customers who are on flex rates, and therefore are not subject to the increase. (CII Statement No. 1, pp. 7-8; PSU Statement No. 1-R, pp. 6-10.) As a result of negotiations, the Parties agreed to reduce the total increase to the LDS/LGSS class from the Company's proposal of $1,845,302 to $1,100,000, which represents a slightly lower percentage (3%) of the total Settlement increase than originally proposed by Columbia. (Settlement Appendix "A".)

c. Other Charges and Riders

Consistent with the Commission's June 23, 2011 Final Rulemaking Order at Docket No. L-2008-2069114, Columbia designed a gas procurement charge ("GPC") in order to remove natural gas procurement costs from base rates and to recover those fuel acquisition costs as part of the "price to compare," on a revenue neutral basis via an automatic adjustment charge only to be recalculated in a base rate case. In the settlement of Columbia's 2015 base rate case at Docket No. R-2015-2468056, parties to the settlement agreed not to propose a change to the Company's GPC for a period of two base rate cases, or five years, whichever occurred first. No party proposed a change to Columbia's GPC in this proceeding. The Settlement in this proceeding provides that the GPC will continue at the current rate of $0.00695/therm. (Settlement ¶ 34.) Continuation of the GPC at the current rate honors the Commission-approved agreement of the parties in Columbia's prior base rate proceeding and should be approved.

The Merchant Function Charge ("MFC") is a component of the "price to compare". Columbia proposed a MFC of 1.52% for residential customers and 0.37% for non-residential customers, which represent a decrease from the currently-effective MFC rates. No party opposed the MFC as filed by Columbia. The Settlement provides that the MFC shall be 1.52% for residential customers and 0.37% for non-residential customers. The revised MFC rates shall be reflected in the Purchase of Receivables ("POR") discount rates. (Settlement ¶ 35.) No party opposed Columbia's MFC as filed, and Columbia therefore submits that this settlement provision is in the public interest and should be approved.

d. Conclusions as to Rate Design

The proposed changes to the rate design for all customer classes, as set forth in Appendix "B" to the Settlement, reflect an accord reached between the Joint Petitioners as to the rate design to be used to recover the rate increases allocated under the Settlement to the Company's customers. Columbia submits that the Settlement reflects an acceptable compromise of the competing litigation positions of the Joint Petitioners relative to rate design.

C. UNIVERSAL SERVICE AND CONSERVATION

The Settlement includes several provisions related to Columbia's Universal Service Programs. First, the Settlement resolves the issue of funding sources for Columbia's Hardship Fund. The Hardship Fund is an intermediate level of assistance between the Low-Income Home Energy Assistance Program ("LIHEAP") and Columbia's Customer Assistance Program ("CAP"), and provides up to $500 of additional assistance to low-income customers. (Columbia Statement No. 14-R.) As such, Columbia's Hardship Fund is critically important to the Company's portfolio of low-income programs. (Columbia Statement No. 14-R.) In direct testimony, Columbia proposed to use the residential portion of pipeline penalty credits and refunds as a funding source for the Hardship Fund while the Company continues to develop plans to seek funding from voluntary sources. (Columbia Statement No. 14, p. 8.) OCA and CAUSE-PA supported the Company's proposed treatment of pipeline penalty credits and refunds, while I&E opposed the Company's proposal. (OCA Statement No. 4, p. 43; CAUSE-PA Statement No. 1, pp. 4-10; I&E Statement No. 6, pp. 5-9.)

The Settlement adopts Columbia's proposal with certain conditions. Specifically, the Settlement provides that Columbia may use the residential portion of pipeline penalty credits and refunds received through February 28, 2018, as a funding source for the Hardship Fund. Prior to February 28, 2018, Columbia may file a request with the Commission to continue to use the residential portion of pipeline penalty credits and refunds to fund the Hardship Fund. (Settlement ¶ 41.) Columbia also agrees to remove the current $375,000 Hardship Fund recovery from Rider USP. (Settlement ¶ 41.)

In accordance with the Commission's Order in Columbia's 2015 base rate proceeding at Docket No. R-2015-2468056, Columbia has engaged in efforts to examine additional fundraising opportunities for its Hardship Fund. (Columbia Statement No. 14, pp. 2-2-3.) As part of the Settlement, Columbia agrees to continue to develop plans, in consultation with its Universal Service Advisory Council, to seek out additional funding from voluntary sources. Columbia will provide a report on ideas developed and implemented to increase voluntary contributions to the Hardship Fund as part of any request to continue applying pipeline penalty credits and refunds to the Hardship Fund, as well as in its next base rate proceeding and its next Universal Service Plan proceeding. Further, Columbia commits to continue to explore joint outreach efforts with other regional public utilities and community agencies for funding of its Hardship Fund. (Settlement ¶ 41.)

This Settlement term is in the public interest because it establishes an appropriate funding source for the Company's Hardship Fund while the Company continues to undertake efforts to seek additional sources of voluntary funding. Columbia has proposed and the Commission has approved similar treatment of pipeline penalty credits and refunds in the past, and a petition seeking approval to use Columbia Gas Transmission ("TCO") penalty credit proceeds that Columbia received in 2014 for the Hardship Fund is currently pending before the Commission. (Columbia Statement No. 14, pp. 6-8.) Because Columbia plans to retain any funds over $375,000 received in a single year to fund future program years, Columbia estimates that the amount of pipeline penalty credits and refunds that is the subject of Columbia's currently pending petition, if approved, will adequately fund the Hardship Fund for nearly three years. (Columbia Statement No. 14, p. 8.) The Settlement also allows Columbia, interested parties and the Commission to examine the use of pipeline penalty credits and refunds as a source of funding for the Hardship Fund in a future proceeding. Finally, the Settlement complies with the Commission's directive in Columbia's 2015 base rate proceeding that the Company remove Hardship Fund recovery from Rider USP. For all of these reasons, the Hardship Fund provisions of this Settlement should be approved.

In direct testimony, CAAP and OCA expressed concern with the effect of a rate increase on low-income customers and suggested a number of actions Columbia could undertake to mitigate the effects of a rate increase upon low income customers.[7] (CAAP Statement No. 1, pp. 4-7; OCA Statement No. 4, pp. 7-39.) In the Settlement, Columbia has agreed to undertake several initiatives to address CAAP's and OCA's concerns.

First, Columbia agrees to review the list of customers with high CAP credits (over $1,000) from the prior year and prioritize those customers for weatherization under Columbia's Low Income Usage Reduction Program ("LIURP"), when possible. Once this list has been exhausted, Columbia will use the high usage CAP customer list as well as eligible customers requesting weatherization. (Settlement ¶ 47.) This will focus Columbia's LIURP efforts on high usage low-income customers.

Columbia currently works with Community Based Organizations ("CBOs") to meet the needs of its low-income customers. (Columbia Statement No. 14-R, pp. 12-13.) The Settlement reaffirms that Columbia will continue to engage CBOs to complement its low-income program. (Settlement ¶ 43.) As part of the Settlement, Columbia will continue to partner with CBOs, including member agencies of CAAP and the

[7] CAUSE-PA presented rebuttal testimony related to the low-income customer issues raised by OCA. (CAUSE-PA Statement No. 1-R, pp. 10-13.)

Pennsylvania Weatherization Providers, in the development, implementation and administration of its LIURP program. (Settlement ¶ 43.)

OCA also raised concerns regarding Third Party Notifications, and notices of available programs for low-income customers. Under the Settlement, Columbia agrees to extend its Third Party Notification Program to include all CAP reminder notices, including notices of potential CAP removal such as income verification requests. Additionally, Columbia agrees to make Third Party Notification forms available at local CBOs, and will encourage CBOs to include Third Party Notification forms in processing other assistance, recognizing that customers should be informed that completion of a Third Party Notification form is completely voluntary. (Settlement ¶ 44.) Columbia agrees to provide brochures on all programs to non-utility access points, such as CBOs. Columbia shall authorize and encourage CBOs to disseminate brochures to applicants for other assistance. (Settlement ¶ 45.)

Columbia is an industry leader in programs to assist low income customers. The commitments to Universal Service and Energy Conservation contained in the Settlement reflect the Company's continued support for these programs, are in the public interest, and should be approved.

CAAP also proposed a $700,000 increase in LIURP funding, from $4,750,000 to $5,450,000 annually. The Settlement does not adopt this proposal. Instead, the Settlement provides that Columbia's LIURP funding will continue at the level of $4.75 million per year, as agreed to in the Commission-approved settlement of Columbia's base-rate proceeding at Docket No. R-2014-2406274. The 2014 base rate case settlement provided that the parties agreed not to propose any further change to LIURP funding for a period of three years, commencing with the effective date of rates in that proceeding. Any unspent funds will be carried over and added to the following year's funding. (Settlement ¶ 42.)

This Settlement term is in the public interest because the current level of annual LIURP funding is sufficient to address the needs of low-income customers, and it appropriately balances the benefits of LIURP spending with the cost paid by other customers. (Columbia Statement No. 14-R, pp. 2-3.) Further, in the settlement of Columbia's 2014 base rate proceeding at Docket No. R-2014-2406274, to which CAAP was not a party, the Joint Petitioners agreed that Columbia's LIURP funding would be increased to $4.75 million annually and that the parties would not propose any further change to LIURP funding for three years. (Columbia Statement No. 14-R, p. 4.) The Settlement in this proceeding acknowledges that agreement. Good reason exists for upholding the prior settlement terms, which not only were agreed to by all parties in the 2014 proceeding after examining the issue of LIURP funding, but subsequently approved by the Commission. No new circumstances exist that justify changing the agreement that was reached by the active parties in the 2014 case, most of whom are also parties in the current proceeding. For these reasons, the Settlement term should be approved.

In direct testimony, OCA recommended that the base participation level of the existing offset to the Universal Service Rider be reduced from 25,300 participants to 20,500 participants to reflect a purported reduction in CAP participation. (OCA Statement No. 4, p. 5.) The offset is based on the premise that the Company receives reductions in bad debt, and credit and collection costs, including cash working capital reductions, when low-income customers are moved from regular rates to Columbia's CAP. (Columbia Statement No. 14-R, p. 6.) In the settlement of Columbia's 2009 base rate proceeding, the parties agreed to a 7.5% offset to CAP credit amounts and pre-program arrearage forgiveness for CAP participation over 25,300 on an annual average basis. Columbia has not challenged the offset in recent cases even though the Company has not made a working capital claim in recent cases. (Columbia Statement No. 14-R, p. 7.) Columbia opposed OCA's proposal to reduce the base participation level of the existing offset to the Universal Service Rider because non-CAP low-income customers and associated net write-offs and collection costs have not decreased. (Columbia Statement No. 14-R, p. 7.)

As part of a global compromise, the Settlement provides that the base participation level for Columbia's CAP will be reduced from 25,300 to 23,000.[8] The universal service cost offset will remain at 7.5%. (Settlement ¶ 46.) Reducing the base participation level to 23,000 represents a compromise of Columbia's and OCA's positions on this issue, is in the public interest, and should be approved.

D. PROGRAMS TO EXPAND THE AVAILABILITY OF GAS SERVICE

In direct testimony, Columbia presented two new proposals designed to expand the availability of natural gas service in Columbia's service territory: (1) reimbursement up $1,000 per unit to builders/developers for the installation of house piping and/or venting in multifamily homes when projected revenues exceed projected costs by a certain threshold, and (2) the ability to charge rates for large commercial and industrial ("C&I") customers above current tariff rates in lieu of the C&I customer paying the

[8] Columbia notes that this provision does not create a CAP enrollment limit. Indeed, as directed by the Commission, Columbia removed its CAP enrollment limit in its current Universal Service and Energy Conservation Plan. *Columbia Gas of Pennsylvania, Inc. Universal Service and Energy Conservation Plan for 2015-2018 Submitted in Compliance with 52 Pa. Code § 62.4*, Docket No. M-2014-2424462 (July 8, 2015) at 20.

entire cost of enabling the C&I customer to receive natural gas service as an up-front deposit. (Columbia Statement No. 13, pp. 4-10.)

Columbia presented these proposals to expand the availability of natural gas service in response to encouragement from the Commission to reduce obstacles that prevent individuals from converting to natural gas service. In Columbia's 2015 base rate proceeding, the Commission approved Columbia's proposal to provide an allowance of 150 feet of main per residential applicant, an allowance of 150 feet of service line in areas where the Company owns the service line, and a reimbursement of up to $1,000 for house piping costs per applicant on qualifying projects. (Columbia Statement No. 13, p. 2.) In her statement regarding Columbia's New Business Proposals, then-Commissioner Witmer stated that Columbia's programs "should enable more individuals to receive natural gas service and they serve as a positive step in removing barriers for customers that desire to convert to natural gas." (Columbia Statement No. 13, p. 3.)

Columbia proposed its multi-family house line reimbursement program in the current proceeding to further expand residential customers' ability to convert to natural gas service. Absent additional incentives, builders/developers of multi-family units can be dissuaded from equipping units with natural gas capabilities based on the increased costs of installing necessary piping and venting as compared to less expensive electric alternatives. (Columbia Statement No. 13, pp. 4-7.)

In its direct testimony, I&E expressed concern that Columbia's proposed multi-family house line reimbursement could benefit the builder/developer rather than the potential residential customer. I&E also questioned the need for the program. (I&E Statement No. 2, pp. 17-20.) As part of a global settlement and in response to I&E's

concerns, the Settlement does not adopt Columbia's multi-unit inventive proposal at this time. (Settlement ¶ 49.) However, the Settlement provides that Columbia reserves the right to present this proposal in a future proceeding and all parties reserve their rights to support or oppose such proposal if filed. (Settlement ¶ 49.)

Columbia recognizes that the up-front deposit presents a significant challenge for not only residential customers, but also for large C&I customers seeking to convert to natural gas service. Columbia's large customer incentive ("LCI") proposal responds to the request of Chairman Brown and Commissioner Powelson in their Joint Motion on February 25, 2016 in which the Commissioners urged utilities to "promote the consideration of special natural gas rates for owners and operators of CHP facilities." (Columbia Statement No. 13, pp. 3-4.) Under Columbia's LCI Program, the Company proposed that, for new applicants projected to use more than 64,400 therms annually, the Company have the ability to receive the full deposit up front or to negotiate to receive some or all of the deposit over time, through an increase in charges to the customer. This negotiated rate would be above the Company's current applicable rate structure to recover from the customer the uneconomic costs of the main line extension to serve the customer. The rates portion of the deposit to be paid up front and terms of the agreement would be stipulated on an individual basis between each customer who elects this option and the Company. (Columbia Statement No. 13, pp. 9-10.)

OCA presented testimony regarding Columbia's LCI proposal. OCA did not oppose Columbia's proposal, but suggested a number of reporting requirements, many of which were adopted in the Settlement. OCA also expressed concern regarding the treatment of possible unpaid balances. (OCA Statement No. 3, pp. 38-40.) The Settlement approves Columbia's LCI proposal with the following modification:

customers participating in the program will be required to pay 30% of the uneconomic portion upfront or have a repayment period that does not exceed ten (10) years. These provisions mitigate against large deferred balances remaining unpaid for an extended period, and thus are responsive to OCA's concerns. (Settlement ¶ 48.) As part of the Settlement, Columbia also agrees to provide the following information related to Columbia's LCI proposal, as applicable:

a) Main and service investment per project;

b) Net Present Value ("NPV") model results for each project, inclusive of the main and service allowances;

c) Required LCI deposit by project;

d) Number of customers connected by each project and number of subsequent connections;

e) Annual non-gas revenues received by project, separated into base rate and LCI repayment revenues (principal and interest stated separately);

f) Annual usage by project;

g) Average investment cost per customer by project; and

h) Number of new service requests for projects in which the NPV model is run, but the project does not proceed to construction.

(Settlement ¶ 48.) These reporting requirements, as requested by OCA, will provide interested parties with plentiful information to evaluate the program. The information to be provided will assist other parties and the Commission in assessing the impact of Columbia's new service initiatives, is in the public interest and should be approved.

Also, the LCI program will complement Columbia's currently effective programs to expand the availability of gas service, including the proposals approved in Columbia's 2015 base rate proceeding as well as the currently effective Pilot Rider New Area Service, which was established at Docket No. R-2014-2407345, by expanding conversion opportunities to C&I customers, not just residential customers. Efforts to increase the availability of low cost natural gas service throughout Columbia's service territory are consistent with the Commission's goals and are in the public interest.

E. NATURAL GAS SUPPLIER ISSUES

The Settlement contains several terms intended to address concerns raised by the NGS Parties and Direct Energy. The primary areas of concern for these suppliers focused on the calculation of penalties for noncompliance with operational orders, the availability and transmission of customer usage data, and the process by which customers can elect to change suppliers. The Settlement contains various provisions to address these issues.

Columbia issues operational orders, when necessary, based on several factors, including the need to manage nominations to its receipt points, avoid exposure to interstate pipeline penalties and/or operational issues, and ensure customers receive their required supplies. (Columbia Statement No. 16-R, pp. 6-7, 19.) Penalties seek to deter noncompliance with operational orders, which could threaten the operational integrity of Columbia's system. Suppliers on Columbia's system incur penalties when they fail to meet their delivery obligations. Under Columbia's average day program, CHOICE suppliers incur a penalty for deviating from the required daily delivery requirements, which are 1/365th of customers' average annual requirements.[9] (Columbia Statement No. 16-R, pp. 7-8.) General Distribution Service ("GDS") suppliers are not required to comply with a daily delivery requirement. However, GDS suppliers must comply with operational orders when they are in effect. The NGS Parties, Direct Energy and PSU (a GDS customer) all challenged the imposition and amount of penalties.

In response to these challenges, the Settlement revises how penalties are calculated. Specifically, with respect to the calculation of penalties for over- and under-deliveries during an operational order, Columbia agrees to adopt an index-based penalty structure. The revised penalty structure, for non-compliance with Operational Flow Orders ("OFOs") and Operational Matching Orders ("OMOs"), as well as the non-compliance charges related to Choice deliveries, shall be three (3) times the highest of the midpoint prices reflected in Platts Gas Daily for the day of the OMO or OFO non-compliance, from the applicable indices, depending upon the market area utilized. Appendix "C" to the Settlement sets forth the applicable areas. In the event no midpoint prices are published in Platts Gas Daily on a particular day, the highest price paid by Columbia on that day shall be used as the index price. Columbia shall update the applicable indices on 60 days' notice to Customer Proxies in the event of a change in applicable indices. (Settlement ¶ 53.) The modifications to Columbia's penalty structure will continue to encourage compliance with suppliers' delivery requirements and should be approved. By linking the amount of penalties to market prices, the Settlement avoids the imposition of unreasonable penalties. However, by applying a

[9] The CHOICE program is a firm capacity program for Priority 1 residential and small commercial customers. (Columbia Ex. No. 14, Sch. 2.)

multiplier to the index price, the penalties continue to provide a strong incentive to comply with operational orders and CHOICE delivery requirements.

Another issue raised by suppliers concerned Columbia's current requirement that customers complete a new customer application form each time a customer changed suppliers. Columbia's process has been to have customers execute the entire form in order to ensure Columbia has current customer contact information. (Columbia Statement No. 15-R, pp. 5-6.) As a compromise, and to resolve supplier issues in this proceeding through settlement, Columbia has agreed to utilize pages 4 and 5 of the existing customer application, plus an additional page requiring updated contact information (emergency, billing and mailing), as a shortened version of the agency form for GDS customers who seek to change their NGS supplier. This shortened agency form shall be effective for contracts rendered on or after thirty (30) days after the entry of the Commission Order approving this Settlement. (Settlement ¶ 51.) This provision will make it more convenient for GDS customers to switch suppliers and should be approved.

Suppliers also complained that they could only obtain access to Columbia's Aviator information system if their customer gave them access to the system. Columbia explained that its Aviator system is currently designed to allow customers only to change the designation of who has access to their information in Aviator. Recognizing that some customers apparently fail to make designations or update their designations, Columbia has agreed here to a compromise that would have Columbia make changes to supplier designations with the consent of the customer. Specifically, Columbia agrees that, as soon as possible, but in no event no later than six months following the entry of a Commission Order approving the Settlement, Columbia will modify its supplier agency form (pages 4-5) and its Aviator Agreement to include authorization for the supplier to have access to all of the customer's usage information on the Aviator system, or a comparable current or future system and to obtain revised authorization forms from all current customers. With these consents, Columbia shall insure that a customer's Aviator data shall be available to the customer's current supplier. (Settlement ¶ 52.) Because this change requires system IT modifications, the change will not become effective immediately. Making customer usage data available timely to a customer's current supplier will facilitate suppliers' ability to serve their customers in accordance with any delivery requirements Columbia imposes. Therefore, this provision is in the public interest and should be approved.

The NGS Parties also opposed the requirement that suppliers provide "enrollment type"[10] information as part of the NGS customer submission procedure. (NGS Parties Statement No. 1, p. 5.) The NGS Parties view this as "marketing" information that should not be shared with the Company. (NGS Parties Statement No. 1, p. 6.) To address the NGS Parties' concern, Columbia has agreed to remove the designation of enrollment type from its NGS customer submission procedure. (Settlement ¶ 50.)

Columbia also proposed modifications to its Rules Applicable to Distribution Services ("RADS") in this proceeding. Specifically, Columbia proposed new section 2.7.2 applicable to GDS customers which provided, "in order to facilitate compliance with upstream pipeline restrictions and to maintain operational integrity, it may be necessary, from time to time, for the Company to require a General Distribution Service

[10] Enrollment type identifies the manner in which the NGS acquired the customer, i.e., web, telephone or in person contact.

Customer Proxy to schedule natural gas supplies to the Company at multiple transmission pipeline delivery points as designated by the Company." Columbia proposed a similar provision in RADS 4.9.5, applicable to the CHOICE program. (Columbia Statement No. 16-R, p. 4.) Columbia proposed this language for two primary reasons. First, there may be times when Columbia needs to require customers and suppliers to deliver quantities to the Company from alternate and/or multiple transmission pipeline delivery points due to changing operational conditions. (Columbia Statement No. 16-R, p. 5.) For example, if the Company is advised by an upstream pipeline that service at one or more receipt points will be interrupted, the Company could notify affected Customer Proxies of alternative delivery points that could be utilized rather than potentially curtailing service to the customers affected by the service interruption. (Columbia Statement No. 16-R, p. 5.) Second, the Company may need to designate an alternative delivery point on an upstream pipeline where Customer Proxies are able to continue to deliver supplies to the Company in the event there is a pipeline restriction or operational order on the upstream pipeline that restricts delivery to the Company at one or more delivery points. (Columbia Statement No. 16-R, p. 5.)

The NGS Parties and Direct Energy expressed concern that the proposed language was too broad and did not specify the conditions under which the Company would alter the delivery requirements. (NGS Parties Statement No. 1, pp. 2-4; Direct Energy Statement No. 1, pp. 12-13.) To address the NGS Parties' and Direct Energy's concerns, Columbia has agreed to withdraw RADS 2.7.2 from this case. (Settlement ¶ 56.) Instead, RADS 2.7.2 will be discussed as part of a collaborative between Columbia, the parties to this proceeding and all interested suppliers on the Company's system, to be held pursuant to the Settlement, as fully described below. For purposes of the Settlement, the NGS Parties do not oppose the inclusion of RADS 4.9.5 in Columbia's tariff at this time. (Settlement ¶ 56.) Because Columbia's average day program for CHOICE customers requires average day deliveries in summer months when customer requirements at a scheduling point may be well below the required deliveries, it is crucial that there be a mechanism in place to direct deliveries to points where the gas can flow to interstate storage. (Columbia Statement No. 16-R, pp. 7-9.) However, the Settlement provides that the parties will discuss how transparency may be achieved as to Columbia's nominations to alternate delivery points under RADS 4.9.5, including information that Columbia could share with suppliers regarding actual nominations, as part of the collaborative to be held pursuant to the Settlement. (Settlement ¶ 57.)

Within sixty (60) days of the entry of a Commission Order approving this Settlement in its entirety, Columbia shall convene a collaborative with the parties to this proceeding and all interested suppliers on its system to discuss new approaches to deal with ongoing pipeline delivery constraints, including the creation of new market "orders". The collaborative shall conclude within 120 days of its initiation, unless extended by consensus of the parties participating. Any resolutions requiring tariff changes shall be reflected in a proposed non-general tariff filing made by Columbia at the conclusion of the collaborative. At the conclusion of the collaborative, Columbia will file a letter report with the Commission summarizing the results and consensus recommendations of the collaborative. (Settlement ¶ 57.)

This Settlement provision is in the public interest and should be approved because it provides an opportunity for interested parties to discuss important supplier topics, such as pipeline delivery constraints as well as other issues affecting Columbia, its customers, and suppliers on Columbia's system. Further, the Settlement provision ensures that the Commission will be provided with relevant information concerning the outcome of the collaborative.

Direct Energy also alleged that it does not have reasonable and continuous access to the customer usage data, including real time data, needed to respond to operational orders and thus avoid the imposition of a penalty. (Direct Energy Statement No. pp. 6-9.) Columbia explained that, if a meter does not have daily read capability, it cannot provide daily usage data. Daily usage data is available to Columbia, the customer, and any customer designee on a next day basis for those daily read meters with Electronic Flow Correctors ("EFC") that have installed and maintained an operable telephone line. However, not all daily read meters have an ECF. If the daily read meter with an EFC does not have a dedicated telephone line or if the telephone line is inoperable, daily usage data would not be accessible on a next-day basis. Rather, it would be available after a site visit and manual upload into the Aviator system. (Columbia Statement No. 15-R, pp. 8-9.) In response to Direct Energy's concerns, Columbia has agreed that within ninety (90) days of the entry of an Order by the Commission approving this Settlement:

> (a) Columbia will propose in a non-general tariff filing that all customers eligible to be served on Rate Schedules SDS, LDS and MLDS [Small Distribution Service, Large Distribution Service, and Main Line Distribution Service] must have installed EFCs and telephonic equipment to transmit daily usage information to Columbia. Columbia further agrees to propose that it install, own, operate and maintain all equipment, including telephonic or similar technology, provided that Columbia is

granted rate recovery of reasonable and prudent capital and operating and maintenance costs to own, operate and maintain the capability to obtain daily information from such customers. To the extent that any associated costs will not be rate based, Columbia shall be permitted to seek to create a regulatory asset for such costs and propose to recover them in its next base rate case. All Parties retain their rights to support or oppose such proposal in the non-general rate filing. Issues related to cost allocation and rate recovery of the costs associated with this equipment will be addressed in the Company's next base rate proceeding.

b) For customers who have EFC and operating telephonic equipment to transmit daily usage information installed, Columbia agrees on a commercially reasonable basis to provide customer usage data in the GTS0005 Reports and in the Aviator-EMDCS data base by 1 PM following the day for which the data is being provided. (Settlement ¶ 54.)

Subsequent to the Commission's approval of the non-general tariff filing and Columbia's installation of equipment to obtain daily information, in addition to any other remedy a supplier may have, a supplier shall be subject to Modified OMO Penalties with respect to any OMO customer with an EFC and operating telephone equipment for which Columbia does not have daily usage data available, by the end of an OMO Period. An OMO Period is defined as one or more OMO days issued within a calendar month. Modified OMO penalties shall mean the penalty that would otherwise be applicable pursuant to Columbia's index-based penalty structure as provided for in the Settlement in this proceeding except that the penalty multiplier shall be 1.5 times rather than 3 times. (Settlement ¶ 55.)

Columbia does not seek approval of the non-general tariff filing in this proceeding. Rather, the Settlement simply provides that Columbia will make such a filing within 90 days of a Commission Order approving this Settlement. The Settlement provision is in the public interest because it will allow Columbia, interested parties and the Commission to examine issues related to Columbia's proposal in the non-general tariff filing. Further, the Settlement provision that provides for the penalty adjustment upon the Commission's approval of the non-general tariff filing represents a compromise between the positions of Direct Energy and Columbia and should be approved.

F. RESTORATION COSTS

I&E Witness Kline identified in direct testimony that Columbia's replacement cost per mile has increased. (I&E Statement No. 5, pp. 11-12.) However, Columbia notes that in 2015 its replacement cost per mile and percentage of paving costs to total costs declined. (Columbia Statement No. 7-R, p. 9.) As explained by Columbia Witness Soyster, Columbia makes every effort to reduce replacement costs when possible. Columbia evaluates all projects during the design phase to determine least-cost options. When feasible, Columbia avoids temporary restoration work and partners with other utilities to split project costs. Further, Columbia has formalized a restoration review process in which a cross-functional team works with municipalities to determine the amount of restoration and permitting costs prior to the start of construction. (Columbia Statement No. 7-R, pp. 6-12.)

In an effort to address rising pipeline replacement costs, Columbia will continue its efforts to reduce restoration costs, through efforts including, but not limited to, coordinating pipe replacement projects with other street projects, using private rights-of-way, avoiding temporary restoration, and replacing pipe using trenchless construction techniques, all where technically, operationally and economically feasible. (Settlement ¶ 58.) This Settlement provision is in the public interest because it provides for Columbia's continued efforts to reduce restoration costs where feasible.

G. TRANSACTION FEES PROPOSAL

In this proceeding, Columbia proposed to include all residential payment channel fees in the cost of service. Currently, Columbia's customers can pay their bills via mail, monthly debit from their financial account, authorized walk-in locations, one-time electronic payments, or through a third-party processor via debit card, credit card or Automated Clearinghouse ("ACH"). The processing fees associated with all but third party credit card, debit card, ACH and walk-in locations are currently included in the cost of service. Columbia has frequently received comments from customers suggesting that they would prefer to pay their bill online via the method of their choice without incurring an additional fee to do so. (Columbia Statement No. 13, pp. 10-11.) Columbia's proposal to include all residential transaction fees in the cost of service is responsive to these customer requests.

The Settlement provides that customers will not be charged separate processing fees for bill payments using third-party debit card, credit card, ACH or walk-in locations. (Settlement ¶ 37.) All processing fees will be considered "above-the-line" for ratemaking purposes. Parties reserve their rights to challenge the recovery of processing fees through rates in a future base rate proceeding, and in response, Columbia reserves the right to cease payment of such third-party costs. (Settlement ¶ 37.) The inclusion of all transaction fees in the cost of service will enhance the overall experience of Columbia's customers and help avoid delays in processing payments made through unauthorized agents by encouraging customers to use Columbia's authorized bill-pay agents. (Columbia Statement No. 13, pp. 11-12.) Therefore, this Settlement term is in the public interest and should be approved.

III. CONCLUSION

The Settlement is the result of a detailed examination of Columbia's proposals, multiple rounds of discovery, testimony, and compromise by all active parties. Columbia believes that fair and reasonable compromises have been achieved on the settled issues in this case, as is evidenced by the global agreement reached on all issues in this proceeding. Columbia fully supports this Settlement and respectfully requests that the ALJ recommend that the Commission approve the Settlement in its entirety without modification.

Respectfully submitted,

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Dated: September 2, 2016

Attorneys for Columbia Gas of Pennsylvania, Inc.

Appendix F

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**R-2016-2529660**
	:	
Columbia Gas of Pennsylvania, Inc.	:	

BUREAU OF INVESTIGATION AND ENFORCEMENT
STATEMENT IN SUPPORT OF
JOINT PETITION FOR SETTLEMENT
OF RATE INVESTIGATION

TO ADMINISTRATIVE LAW JUDGE KATRINA DUNDERDALE:

The Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Commission"), by and through its Prosecutor Carrie B. Wright, hereby submits that the terms and conditions of the foregoing *Joint Petition For Settlement* ("Joint Petition" or "Settlement") are in the public interest and represent a reasonable and equitable balance of the interests of Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company"), Columbia's customers, and the parties to the Settlement Agreement. The parties have conducted extensive formal and informal discovery and have participated in numerous settlement conferences. The extensive and open discussions culminated in the attached Settlement Agreement. I&E requests approval of the Joint Petition based on I&E's determination that the Settlement Agreement meets all the legal and regulatory standards necessary for approval. "The prime determinant in the consideration of a proposed Settlement is whether or not it is in the public interest."[1] The Commission has recognized that a settlement "reflects a compromise of the positions held by the parties of interest, which, arguably fosters and promotes the public interest."[2] As a product of negotiation and compromise between multiple parties, this Settlement Agreement reflects concessions from Columbia's original rate request. Accordingly, the Bureau of Investigation and Enforcement believes that the terms and conditions of the Joint Petition are in the public interest.

In support of this position, I&E offers the following:

I. INTRODUCTION

A. Legal Landscape on Public Utilities

A business may acquire "public utility status" when that business is the sole organization that maintains the infrastructure utilized in providing an essential service to the public for compensation.[3] As duplicating the vast and costly fixed physical infrastructure (e.g., substations, poles, lines, etc.) and allowing multiple businesses to provide the essential service would be wasteful, the public utility obtains a natural

[1] *Pennsylvania Public Utility Commission v. Philadelphia Electric Company*, 60 PA PUC 1, 22 (1985).
[2] *Pennsylvania Public Utility Commission v. C S Water and Sewer Associates*, 74 PA PUC 767, 771 (1991).
[3] James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press: New York (1961), at 3-14; 66 Pa. C.S. § 102.

monopoly as the sole service provider in the extended geographic service territory.[4] In order to protect consumers, the public utility's rates and services are regulated.[5] Price regulation strives to replicate the results of effective competition.[6]

As a public utility, a natural gas distribution company ("NGDC") shall provide just and reasonable rates to customers receiving service in the Commonwealth of Pennsylvania.[7] A public utility is entitled to a rate that allows it to recover those expenses that are reasonably necessary to provide service to its customers and allows the utility an opportunity to obtain a reasonable rate of return on its investment.[8] A public utility shall also provide safe and reliable service by furnishing and maintaining adequate facilities and reasonable services and by making the necessary improvements thereof.[9]

B. I&E's Role

Through its bureaus and offices, the Commission has the authority to take appropriate enforcement actions that are necessary to ensure compliance with the Public Utility Code and Commission regulations and orders.[10] The Commission established I&E to serve as the prosecutory bureau to represent the public interest in ratemaking and utility service matters, and to enforce compliance with the Public Utility Code.[11] By representing the public interest in rate proceedings before the Commission, I&E works to

[4] *See id.*; 66 Pa. C.S. § 2802 (it is in the public interest for the distribution of electricity to be regulated as a natural monopoly by the Commission).
[5] *See id.*; 66 Pa. C.S §§ 1301, 1501.
[6] *See Cantor v. Detroit Edison*, 428 U.S. 579, 595-6, fn. 33 (1976).
[7] 66 Pa. C.S. §§ 102, 1301; *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 602-603 (1944).
[8] *City of Lancaster v. Pa. P.U.C.*, 793 A.2d 978, 982 (Pa. Cmwlth. 2002); *see Hope*, 320 U.S. at 602-603.
[9] 66 Pa. C.S. § 1501.
[10] Act 129 of 2008, 66 Pa. C.S. § 308.2(a)(11); 66 Pa. C.S. §§ 101 *et seq,*; 52 Pa. Code §§ 1.1 *et seq.*
[11] *Implementation of Act 129 of 2008; Organization of Bureaus and Offices,* Docket No. M-2008-2071852 (Order entered August 11, 2011).

balance the interest of customers, utilities, and the regulated community as a whole to ensure that a utility's rates are just, reasonable, and nondiscriminatory.[12]

C. History of the Proceeding

On March 18, 2016, Columbia filed Supplement No. 241 to Tariff Gas – Pa. PUC No. 9, containing proposed changes in rates, rules, and regulations calculated to produce approximately $55.3 million in additional annual revenues based upon data for a fully projected future test year ending December 31, 2017. This proposed rate change represents an average increase in the Company's distribution rates of approximately 11.23%. Supplement No. 241 was proposed to take effect on May 17, 2016. Pursuant to 66 Pa. C.S. § 1308(d), the filing was suspended by Commission Order entered April 21, 2016 and assigned to the Office of Administrative Law Judge ("OALJ") for the development of an evidentiary record and Recommended Decision.

Administrative Law Judge Katrina Dunderdale was assigned to preside over the proceeding.

A prehearing conference was held as scheduled on April 28, 2016. At the conference, a schedule was memorialized, identifying filing dates for the parties' testimony, setting dates for public input hearings, and scheduling dates for evidentiary hearings in Harrisburg, Pennsylvania.

Two public input hearings were held in Columbia's service territory on May 25, 2016, in Washington, Pa. at 6:00 p.m., and on June 29, 2016, in Washington, Pa. at 6:00 p.m.

[12] *See* 66 Pa. C.S. §§ 1301, 1304.

Pursuant to the procedural schedule agreed to at the prehearing conference, the parties submitted direct and rebuttal testimony on June 16, 2016 and July 13, 2016 respectively. Surrebuttal testimony was served on July 26, 2016.

On July 28, 2016, the parties informed the ALJ that a partial Settlement had been reached. The first day of evidentiary hearings was canceled.

A hearing was held on August 3, 2016 for the sole purpose of allowing the parties to enter their testimony and exhibits into the record. .

II. DISCUSSION

The Commission encourages settlements, which eliminate the time, effort, and expense of litigating a matter to its ultimate conclusion.[13] Here, the Joint Petitioners successfully achieved a Settlement Agreement of all issues.

The Settlement Agreement is a "Black Box" agreement, which does not specifically identify the resolution of certain disputed issues.[14] Instead, an overall increase to base rates is agreed to and Joint Petitioners retain all rights to further challenge all issues in subsequent proceedings. A "Black Box" settlement benefits ratepayers as it allows for the resolution of a proceeding in a timely manner while avoiding significant additional expenses.[15]

I&E contends that an agreement as to the resolution of each and every disputed issue in this proceeding would not have been possible without judicial intervention. Additional testimony and exhibits, four days of litigious hearings, briefing, and further involvement of

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[13] *Pa. PUC v. Venango Water Co.*, Docket No. R-2014-2427035, 2015 WL 2251531, at *3 (Apr. 23, 2015 ALJ Decision) (adopted by Commission via Order entered June 11, 2015); *See* 52 Pa. Code §5.231.
[14] *See id.* at *11.
[15] *See id.*

the ALJ would have added time and expense to an already cumbersome and complex proceeding. Ratepayers benefit when rate case expenses stay at a reasonable level.[16] The request for approval of the *Joint Petition for Settlement* is based on the I&E conclusion that the Settlement Agreement meets all the legal and regulatory standards necessary for approval. "The prime determinant in the consideration of a proposed Settlement is whether or not it is in the public interest."[17] The Commission has recognized that a settlement "reflects a compromise of the positions held by the parties of interest, which, arguably fosters and promotes the public interest."[18] The Settlement Agreement in the instant proceeding protects the public interest in that a comparison of the original filing submitted by the Company and the negotiated agreement demonstrates that compromises are evident throughout the Joint Petition.

REVENUE REQUIREMENT (Joint Petition, ¶¶A.24-A.37)

Revenue Number

The Settlement Agreement provides for an increase of a $35 million to the Company's annual overall revenue. This increase is $20.3 million less than the $55.3 initially requested by Columbia, or a reduction of approximately 37% of the amount requested. I&E agreed to settlement in the amount of $35million only after I&E conducted an extensive investigation of Columbia's filing and related information obtained through the discovery process to determine the amount of revenue Columbia needs to provide safe,

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[16] *See id.*
[17] *Pennsylvania Public Utility Commission v. Philadelphia Electric Company*, 60 PA PUC 1, 22 (1985).
[18] *Pennsylvania Public Utility Commission v. C S Water and Sewer Associates*, 74 PA PUC 767, 771 (1991).

effective, and reliable service to its customers. The additional revenue in this proceeding is base rate revenue and has been agreed to in the context of a "Black Box" settlement with limited exceptions. The prior Chairman of the Commission has explained that black box settlements are beneficial in this context because of the difficulties in reaching an agreement on each component of a company's revenue requirement calculation, when he stated, the "[d]etermination of a company's revenue requirement is a calculation that involves many complex and interrelated adjustments affecting revenue, expenses, rate base and the company's cost of capital. To reach an agreement on each component of a rate increase is an undertaking that in many cases would be difficult, time-consuming, expensive and perhaps impossible. Black box settlements are an integral component of the process of delivering timely and cost-effective regulation."[19]

This increased level of "Black Box" revenue adequately balances the interests of ratepayers and Columbia. Columbia will receive sufficient operating funds in order to provide safe and adequate service while ratepayers are protected as the resulting increase minimizes the impact of the initial request. Mitigation of the level of the rate increase benefits ratepayers and results in "just and reasonable rates" in accordance with the Public Utility Code, regulatory standards, and governing case law.[20]

Additionally, the Joint Petitioners have agreed to add another layer of protection to the settlement to ensure that Columbia accounts for its need of the increased revenue.

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[19] *See,* Statement of Commissioner Robert F. Powelson, *Pennsylvania Public Utility Commission v. Wellsboro Electric Company,* Docket No. R-2010-2172662. *See also,* Statement of Commissioner Robert F. Powelson, *Pennsylvania Public Utility Commission v. Citizens' Electric Company of Lewisburg, PA,* Docket No. R-2010-2172665.

[20] 66 Pa. C.S. § 1301.

While current regulatory practices allow for the use of a Fully Projected Future Test Year ("FPFTY"), which Columbia used in this proceeding, safeguards are necessary. In accordance with the recommendation made in I&E Statement No. 4, Columbia has agreed to provide to I&E, OCA, OSBA, and the Commission's Bureau of Technical Utility Services ("TUS"), updates to Columbia's Exhibit No. 108, Schedule 1, filed in this proceeding, which include all actual capital expenditures, plant additions, and retirements, by month, for the twelve months ending December 31, 2016. On or before April 1, 2018, Columbia will update Exhibit No. 108, Schedule 1, filed in this proceeding for the twelve months ending December 31, 2017. Columbia has also agreed that in its next base rate proceeding, it will prepare a comparison of its actual expenses and rate base additions for the twelve months ended December 31, 2017 to its projections in this proceeding. I&E fully supports this term because it achieves I&E's goal of timely receiving data sufficient to allow for the evaluation and confirmation of the accuracy of Columbia's projections in advance of its next base rate case filing.

Transaction Fees

The Settlement provides that customers will not be charged a separate processing fee for bill payments using thirst party, debit card, credit card, Automated Clearinghouse ("ACH") or walk-in payment locations. Customers are increasingly choosing these types of alternative payment methods to pay their utility bills. All payment methods except credit card, debit card, ACH and walk-in payments are included in the cost of service. Currently customers who take advantage of these alternative methods of paying their bills pay, not only the fee for the payments methods included in the cost of service, but an additional fee for the credit card, debit card, ACH, or walk-in payment they choose. This proposal will help to eliminate that disparity as increasing numbers of customers choose to pay their bills in these additional ways.

REVENUE ALLOCATION AND RATE DESIGN (Joint Petition, ¶¶B.38-B.40)

A public utility shall not establish or maintain unreasonable differences in rates among rate classes.[21] While there may exist sound justification for some discrepancies in rates under the principle of gradualism, this principle alone does not justify "allowing one class of customers to subsidize the cost of service for another class of customers over an extended period of time."[22] The revenue allocation set forth in the Joint Petition not only reflects a compromise of the Joint Petitioners, but it also produces an allocation that moves each class closer to its actual cost of service. This movement is consistent with the principles of *Lloyd*. Accordingly, this revenue allocation is in the public interest because it is designed to limit customer class subsidies, and to place costs upon the classes responsible for causing those costs.

A utility must be allowed to recover the fixed portion of providing service through the implementation of the proper customer charge.[23] This fixed charge provides Columbia with a steady, predictable level of income which will allow Columbia to recover certain

[21] 66 Pa. C.S. § 1304.
[22] *Lloyd v. Pennsylvania Public Utility Commission*, 904 A.2d 1010, 1019-20 (Pa. Cmwlth. 2006).
[23] Jim Lazar. "Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs." Regulatory Assistance Project (Nov. 2014).

fixed costs such as metering, billing, and payment processing.[24] Limiting the requested increase benefits ratepayers by allowing them to save more money by conserving usage. Shifting costs to the volumetric portion of a customer's bill allows for the immediate realization of the benefit of conserving usage.[25] Designing rates to allow customers to have greater control of their electric bills is in the public interest.

The Joint Petition provides that the residential customer charge will not be increased and will remain at $16.75 per month, as set forth in Columbia's existing tariff. Nearly all parties in this proceeding opposed Columbia's proposal to raise this charge to $19.51 per month ($.65733 per day). Therefore, this resolution represents a significant compromise by Columbia. I&E recommended that the current residential charge of $16.75 per month not be increased in this proceeding in accordance with Witness Apetoh's customer cost analysis.[26] The ultimate resolution of maintaining and not increasing the existing residential customer charge is in the public interest because it protects residential ratepayers while still providing Columbia with adequate revenue. In addition, the Small General Service customer charges will remain at the current levels of $21.25 per month (≤6440 therms) and $48.00 per month (>6440 therms).

The remaining customer charges in the Company's proposed tariff have been modified to reflect the mitigated level of the overall increase. Designing rates in this way allow customers to have greater control of their electric bills is in the public interest because it affords customers the opportunity to decrease their usage in an effort to ultimately keep

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[24] *Id.*
[25] I&E Statement No. 3, p. 21, ln. 4-13.
[26] I&E Statement No. 3, p. 20.

their utility bill lower. Limiting the increase in the customer charge demonstrates a compromise of the interests of the Joint Petitioners and benefits the Company's ratepayers. Therefore, this provision is in the public interest because it more closely aligns the customer charge with the cost to serve those customers. Furthermore, conservation is in the public interest and having a customer charge that is aligned with the cost to serve that customer allows the customer to realize the immediate benefit of conservation on their bill.

UNIVERSAL SERVICE AND CONSERVATION (Joint Petition, ¶¶C.41-C.47)

Hardship Fund

The Settlement provides that Columbia may us the residential portion of pipeline penalty credits and refunds received through February 28, 2018 as a funding source for the Hardship Fund and remove Hardship Fund recovery from the Rider USP.

By way of background, on June 2, 2014, Columbia filed its proposed Universal Service and Energy Conservation Plan for the years 2015 to 2018 at Docket No. M-2014-2424462. The Commission's Tentative Order entered on March 26, 2015 requested comments on the cost recovery funding mechanism for Columbia's Hardship Fund and concern was expressed that voluntary customer contributions would decline as customers became aware that they were already funding the Hardship Fund through rider USP. On July 8, 2015, the Commission stated that it was not persuaded that funding for Columbia's Hardship Fund could not be done through the use of only voluntary funding sources. The Commission then ordered that the issue of whether Hardship Funding should be recovered through rider USP was an issue that needed to be addressed in Columbia's base rate proceeding at Docket No. R-2015-2468056. In the Commission's Final Order, entered December 3, 2015, of that base rate proceeding the Commission stated on page 50 that

> ...the ALJ's recommendation in this proceeding is that Columbia be directed to accelerate its voluntary fundraising efforts for the Hardship Fund and to address removing the hardship funding from its USP Rider as part of its *next* base rate case. We are of the opinion that the ALJ's recommendation provides clear instruction for Columbia to transition to voluntary funding within a definite time period.[27]

Based on that information, I&E recommended in this proceeding that "Columbia fund its hardship fund entirely through voluntary funds and shareholder contributions and cease collecting funds for the Hardship fund through its Rider USP."[28] However, in the spirit of compromise and in recognition of the fact that the time between the last base rate case and the instant case was very short, I&E was willing to agree to using the residential portion of pipeline penalty credits and refunds received through February 28, 2018 as a funding source for the Hardship Fund. I&E recognizes the harm that may occur to the Company's low-income population if funding for the Hardship fund is not put in place by some means. Therefore, for the purposes of this proceeding only, I&E agrees that these funds represent a temporary solution to the problem of finding a funding source for the Hardship fund.

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[27] *Pa. Pub. Util. Comm'n. v. Columbia Gas of Pa., Inc.*, Docket No. R-2015-2468056 (Final order entered December 3, 2015).
[28] I&E St. No. 6, p. 9.

On a going forward basis I&E believes the Company should follow the Commission's directive to find a voluntary funding source for the Hardship fund. While I&E acknowledges that the time period between base rate cases in this instance may have been too short for the Company to find a completely voluntary funding source, I&E also recognizes that the Company itself is the party that determines if, and when, a base rate case is filed. Further, I&E continues to believe that any future use of pipeline penalty credits and supplier refunds to fund the Hardship fund should be reviewed on a cases by case basis by a petition to the Commission, as has been the practice in the past.

Because it would not be in the public interest to deny funding for the Hardship fund, solely for the purpose of this particular proceeding, I&E agrees that the residential portion of pipeline penalty credits and refunds received through February 28, 2018, should be used to fund Columbia's Hardship fund. In addition, the Company's agreement to remove Hardship funding from its Rider USP mitigates the Commission's concern that voluntary funding would decline as customers realized that they were already contributing to the Hardship fund through Rider USP.

PROGRAMS TO EXPAND AVAILABILITY OF GAS SERVICE (Joint Petition, ¶¶D.48-D.49)

Large Customer Incentive

I&E took no position on the Large Customer Incentive proposal.

Multi-Unit Incentive Proposal

Columbia has agreed to withdraw its proposed multi-unit incentive proposal. Under this proposal, Columbia would have reimbursed a developer and/or builder up to $1,000 per unit for the cost of installing house piping or venting of each unit in order for the unit to have natural gas service. While I&E applauds the efforts of the Company to bring natural gas service to more customers, there were several issues I&E found with this proposal. First, the $1,000 benefit of the program did not go to the ultimate Columbia customers. In addition, per I&E's direct testimony Columbia registered in 2015, "a market share of 71.76% in its service territories without giving any builders' incentive."[29] Thus, to I&E the proposal seemed unnecessary. It would not be in the public interest to put the burden of paying for this incentive on the backs of ratepayers when it appears that, at least for the time being, no incentive is necessary to get builders to install natural gas in their multi-family housing units.

NATURAL GAS SUPPLIER ISSUES (Joint Petition, ¶¶E.50-E.57)

I&E has no specific comments on the Natural Gas Supplier issues contained in the Settlement.

OTHER ISSUES (Joint Petition, ¶¶F.58-F.59)

The Settlement provides that Columbia will continue to attempt to reduce restoration costs through various means such as coordinating pipe replacement projects with other street projects, using private rights-of-way, avoiding temporary restoration, and replacing pipe using trenchless construction techniques. In testimony I&E had recommended that Columbia continue to undertake efforts to reduce pipeline replacement and restoration

[29] I&E St. No.2, pp. 18-19.

costs.[30] When restoration and replacement costs are mitigated, both the Company and the ratepayers reap the benefit of these lower costs. Further, efforts such as coordinating pipeline replacement projects with other street projects and avoiding temporary restoration helps to reduce the impact of these types of projects on both the Company and the ratepayers, because it eliminates the need to do things like close roads multiple times.

The remaining issues raised in the I&E Prehearing Memo have been satisfactorily resolved through Discovery and discussions with PPL and are incorporated into the "Black Box" resolution of the revenue requirement in this proceeding. The very nature of a settlement agreement incorporates compromise on the part of all Joint Petitioners. This particular Settlement Agreement exemplifies this principle. Because of the characteristics of "Black Box" settlements, no representation of the resolution of any issue not specifically identified is possible in future proceedings.

III. CONCLUSION

Based on I&E's analysis of the base rate revenue increase requested by Columbia Gas of Pennsylvania, Inc., acceptance of this proposed Joint Petition is in the public interest. Resolution of these issues by settlement rather than continued litigation will avoid the additional time and expense involved in formally pursuing all issues in this proceeding. Increased litigation expenses may have impacted the increase in revenue agreed to in the Joint Petition. As litigation of this rate case is a recoverable expense, curtailment of these charges is in the public interest.

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[30] I&E St. No. 5, p17.

I&E further submits that acceptance of the foregoing Settlement Agreement will negate the need to engage in additional litigation including the preparation of surrebuttal testimony as well as Main Briefs, Reply Briefs, Exceptions and Reply Exceptions. The avoidance of further rate case expense by settlement of these provisions in this Base Rate Investigation proceeding best serves the interests of Columbia and its customers.

The Settlement Agreement is conditioned upon the Commission's approval of all terms and conditions contained therein and should the Commission fail to approve or otherwise modify the terms and conditions of the Settlement, the Joint Petition may be withdrawn by I&E or any of the signatories.

I&E agrees to settle the disputed issue as to the proper level of additional base rate revenue through a "Black Box" agreement with limited exceptions. I&E's agreement to settle this case is made without any admission or prejudice to any position that I&E might adopt during subsequent litigation or in the continuation of this litigation in the event the Settlement is rejected by the Commission or otherwise properly withdrawn by any of the Joint Petitioners.

If the ALJ recommends that the Commission adopt the Settlement Agreement as proposed, I&E has agreed to waive the right to file Exceptions. However, I&E has not waived its rights to file Exceptions with respect to any modifications to the terms and conditions of the Settlement Agreement, or any additional matters, that may be proposed by the presiding officer in her Recommended Decision. I&E also reserves the right to file Reply Exceptions to any Exceptions that may be filed by any active party to this proceeding.

WHEREFORE, the Commission's Bureau of Investigation and Enforcement supports the *Joint Petition For Settlement* as being in the public interest and respectfully requests that Administrative Law Judge Katrina Dunderdale recommend, and the Commission subsequently approve, the foregoing Settlement Agreement, including all terms and conditions contained therein.

Respectfully submitted,

Carrie B Wright

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Dated: September 1, 2016

Appendix G

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2016-2529660
	:	
Columbia Gas of Pennsylvania, Inc.	:	

STATEMENT OF THE OFFICE OF CONSUMER ADVOCATE
IN SUPPORT OF THE
JOINT PETITION FOR PARTIAL SETTLEMENT

The Office of Consumer Advocate (OCA), one of the signatory parties to the Joint Petition for Settlement (Settlement), finds that the proposed terms and conditions of Settlement are in the public interest. The OCA respectfully requests that the Pennsylvania Public Utility Commission (Commission) approve the Settlement without modification for the following reasons:

I. INTRODUCTION

On March 18, 2016, Columbia Gas of Pennsylvania, Inc. (Columbia or the Company) filed Supplement No. 241 to Tariff Gas - Pa. P.U.C. No. 9, to become effective May 17, 2016. The Company, by filing this tariff supplement, sought Commission approval of rates and rate changes that would increase the level of rates that it charges for providing service to its customers. If the proposed tariff supplement were to become effective, Columbia would have benefitted from an opportunity to recover an annual increase in base rate revenues of $55.3 million from its customers. This represents an approximate 11.23% increase in Columbia's annual revenues at present rates. Columbia also proposed to increase the residential customer charge from $16.75 to $19.51 per month. Columbia provides natural gas service to approximately 423,000 residential, commercial, and industrial customers in portions of 26 counties in western, northwestern, central, and southern Pennsylvania.

On March 22, 2016, the OCA filed a Formal Complaint and Public Statement. On March 24, 2016, the Bureau of Investigation & Enforcement (I&E) filed a Notice of Appearance. On April 4, 2016, the Office of Small Business Advocate (OSBA) filed a Formal Complaint and Public Statement. On April 6, 2016, Shipley Energy LLC, AMERIGreen Energy, Interstate Gas Supply, Inc., and Dominion Retail, Inc. (NGS Parties) filed a Petition to Intervene. On April 12, 2016, the Coalition for Affordable Utility Services and Energy-Efficiency in Pennsylvania (CAUSE-PA) filed a Petition to Intervene. On April 25, 2016, The Pennsylvania State University (PSU) filed a Formal Complaint. Also on April 25, 2016, the Columbia Industrial Intervenors (CII) filed a Formal Complaint. Additionally, four (4) residential consumers filed Formal Complaints against Columbia's requested rate increase.

The proceeding was assigned to Administrative Law Judge Katrina L. Dunderdale. By Order entered April 21, 2016, the Commission suspended the implementation of Supplement No. 241 until December 19, 2016, and instituted an investigation into the lawfulness, justness, and reasonableness of the rates, rules, and regulations proposed in Supplement No. 241. A prehearing conference was held on April 28, 2016, and a litigation schedule was adopted. Additionally, two public input hearings were held in the Company's service territory.

The OCA conducted extensive discovery and submitted the testimony of the following witnesses in this proceeding:

<u>Michael J. Majoros, Jr.</u>
OCA Statement No. 1- Direct Testimony (6/16/2016)
OCA Statement No. 1-SR – Surrebuttal Testimony (7/26/2016)

<u>Aaron L. Rothschild</u>
OCA Statement No. 2 – Direct Testimony (6/16/2016)

OCA Statement No. 2-SR – Surrebuttal Testimony (7/26/2016)

Jerome D. Mierzwa
OCA Statement No. 3 – Direct Testimony (6/16/2016)[1]
OCA Statement No. 3-R – Rebuttal Testimony (7/13/2016)
OCA Statement No. 3-SR – Surrebuttal Testimony (7/26/2016)

Roger D. Colton
OCA Statement No. 4 – Direct Testimony (6/16/2016)
OCA Statement No. 4-R – Rebuttal Testimony (7/16/2015)
OCA Statement No. 4-SR – Surrebuttal Testimony (7/26/2016)

The parties to this proceeding agreed to stipulate to the admission of the OCA's testimony into the record, and the testimony was admitted at the evidentiary hearing on August 3, 2016.

Pursuant to the Commission's policy of encouraging settlements that are in the public interest, the OCA, I&E, OSBA, CAUSE-PA, CII, NGS Parties, PSU, and Columbia (Joint Petitioners) held numerous settlement conferences. These discussions resulted in this proposed Settlement. As discussed below, the OCA submits that the proposed Settlement is in the public interest.

II. TERMS AND SETTLEMENT

A. Revenue Requirement

The proposed Settlement provides for an overall distribution base rate increase of $35 million, about $20.3 million less than the rate increase amount originally requested by Columbia. Settlement ¶ 24. The Settlement provides that the increase will not go into effect before December 19, 2016, the end of the suspension period. Settlement ¶ 36.

Based on the OCA's analysis of the Company's filings, testimony by all parties, and discovery responses received, the rate increase under the proposed Settlement represents a result that would be within the range of likely outcomes in the event of full litigation of the case. The

[1] OCA Statement No. 3 was revised and served on the parties on June 30, 2016, to correct Schedule JDM-4. The revised version of OCA Statement No. 3, dated June 30, 2016, was entered into the record at the August 3, 2016 evidentiary hearing.

OCA submits that the increase is appropriate and, when accompanied by other important conditions contained in the Settlement, yields a result that is just and reasonable.

For purposes of calculating the DSIC, the Settlement provides that Columbia will not be eligible to include plant additions until eligible account balances exceed the levels projected by the Company at December 31, 2017, the end of the fully forecasted future test year. This provision results in the Company realizing a higher level of plant investment before any incremental expenditures can be recovered through the DSIC.

B. Revenue Allocation and Rate Design

In its filing, Columbia proposed to allocate approximately $43.1 million of its proposed $55.3 million revenue increase to residential customers. OCA St. 3, Table 6. Under the revenue allocation agreed to by the Joint Petitioners, the residential class would receive approximately $25.9 million of the $35 million increase. Settlement, App. A. As a result, the revenue increase allocated to the residential class is approximately $17.2 million less than the Company's filed-for request. If the Settlement is approved, the average total monthly bill for a residential customer using 87.2 therms per month would be $91.20, compared to $94.22, which would be the average bill under Columbia's proposal.

Based on the OCA's analysis of the Company's filing and discovery responses received, the revenue allocation under the proposed Settlement represents a result that would be within the range of likely outcomes in the event of full litigation of the case. Several parties, including the OCA, provided proposed varied revenue allocations, and the revenue allocation provided in Appendix A represents a compromise of a contentious issue. In the OCA's view, the revenue allocation yields a result that is just and reasonable under the circumstances of this case.

Columbia also proposed to increase the monthly residential customer charge from $16.75 to $19.51 per month. The OCA recommended retaining the current $16.75 charge and submitted evidence demonstrating that the cost of connecting and maintaining a residential customer's account does not support any increase. See OCA St. 3 at 34-37. Consistent with the OCA's position, under the terms of the proposed Settlement, the residential customer charge will remain at the current level of $16.75 per month. Settlement ¶ 38. Applying 100% of the rate increase to the volumetric charges is in the interest of residential customers because it allows customers – including low income customers – to maintain a level of control over their monthly bill through usage reduction measures. Additionally, applying the entire rate increase to the volumetric charges promotes the Commission's general goal of encouraging energy conservation because higher volumetric charges provide an incentive to all residential customers to use less energy. OCA St. 3 at 34.

C. Universal Service and Conservation

The Settlement addresses several issues regarding Columbia's universal service programs that were raised in the testimony of OCA witness Roger Colton. First, Mr. Colton recommended that the Company expand the use of its Third Party Notification Program, in part by increasing the role of community-based organizations (CBOs) in the third party notification process, and by increasing the overall scope of the program. See OCA St. 4 at 28-39. This recommendation was intended to address two trends: increasing numbers of customers enrolled in the Customer Assistance Program (CAP) exiting the program for reasons other than non-payment and decreasing enrollment in assistance programs such as CAP and LIHEAP. OCA St. 4 at 28. Additionally, the OCA raised a concern that the Company's existing Third Party Notification Program only authorized third party notification for shutoff notices. OCA St. 4 at 34. Through the Settlement, the

Company has agreed to "extend its Third Party Notification to include all CAP reminder notices, including notices of potential CAP removal such as income verification requests." Settlement ¶ 44. The Company also accepted Mr. Colton's recommendation to make third party notification forms available at local CBOs. Id. CBOs will be encouraged to include these forms when helping customers with other types of assistance. Id. In addition, the Company has agreed to provide brochures regarding all of its universal service programs to CBOs and other non-utility access points, and will encourage CBOs to provide brochures to customers applying for other forms of assistance. Settlement ¶ 45. This expansion of the Third Party Notification Program will allow the program be carried out more effectively, and will result in improved access by consumers and a greater likelihood that CAP customers will remain enrolled in the program.

Through the Settlement, Columbia has also agreed to adjust the base participation level for its CAP for the purpose of calculating CAP credit offsets from 25,300 to 23,000. Settlement ¶ 46. The base participation level is used to calculate CAP program recovery in rates, so it is important that the number be accurate. As OCA witness Colton testified, the Company's base participation level should be reduced from the current 25,300 number in order to reflect recent reduced participation in the program. OCA St. 4 at 5. Although Mr. Colton recommended that the level be reduced to 20,500 participants, the agreement to reduce base participation to 23,000 represents a reasonable compromise that results in a more accurate calculation of CAP base participation for setting rates.

Additionally, the OCA recommended that Columbia target CAP participants with high usage and thus with high CAP credits with greater energy efficiency investments such as weatherization measures. OCA St. 4 at 15-22. Columbia largely accepted Mr. Colton's recommendation and agreed to "review the list of customers with high CAP credits (over $1000) from the prior year and prioritize those customers for weatherization when possible." Settlement ¶ 47. Once this list has been addressed, the Company will focus on other high usage CAP customers and those customers that have requested weatherization. Id. This provision will help those customers with the greatest need to reduce energy consumption through weatherization, and will maximize the benefit of dollars spent on these measures.

The Settlement also adopts the Company's proposal to use pipeline penalty credits and refunds as a funding source for the Company's Hardship Fund. Settlement ¶ 41. The Settlement, however, provides that pipeline penalty credits and refunds may only be used as a funding source until February 28, 2018, unless the Company obtains Commission approval to continue this use of the residential pipeline penalty credits and refunds, and that the Company must continue exploring other funding sources for the Hardship Fund. Id. Finally, under the Settlement, the Company will remove Hardship Fund recovery from the Rider USP. Id. The OCA submits that these provisions are in the public interest and should be approved, as they ensure that the Hardship Fund will continue to be fully funded until at least February 2018, commits the Company to finding other funding options for the Hardship Fund, and no longer uses recovery through Rider USP dollars to fund the Hardship Fund. Additionally, these Settlement provisions are consistent with the Commission's December 3, 2015 Order, at Docket No. R-2015-2468056, which directed Columbia to address hardship funding in its next base rate proceeding, but allowed the Company to temporarily continue recovering $375,000 through Rider USP for the Hardship Fund while it sought out additional sources of voluntary funding.

D. Programs to Expand the Availability of Gas Service

In this proceeding, Columbia sought approval of a new program called the Large Customer Incentive Program (LCIP). According to the Company, this program is intended to promote the availability of natural gas to large commercial and industrial customers who are currently not connected to natural gas service. CPA St. 13 at 10. Under the proposed LCIP, Columbia will be able to offer potential customers who are projected to use more than 6,440 Dth annually the option of paying the cost associated with extending natural gas service to their property (i.e., the uneconomic portion of the main extension project) through increased charges over a period of time instead of paying this cost in a lump sum, upfront payment. OCA St. 3 at 38. The increased charges would be negotiated between the Company and the new customer, but would be above the Company's current distribution rates. Id. The OCA did not oppose the Company's proposed LCIP, but recommended that if the program is approved, (1) the Company should not be able to recover any unpaid balances stemming from the LCIP from other ratepayers in the event that any of the customers participating in the LCIP default and (2) that reporting requirements be adopted. Id. at 39.

The Settlement adopts Columbia's proposed LCIP with two modifications. Settlement ¶ 48. First, under the Settlement, customers participating in the LCIP will be required to either pay 30% of the uneconomic portion upfront or have a repayment period that does not exceed ten (10) years. Id. In the OCA's view, this modification will reduce the exposure of other ratepayers in the event any customer participating in the LCIP defaults. Second, the Settlement adopts reporting requirements as recommended by the OCA. Settlement ¶ 48. The data collected by the Company should provide Columbia and other parties with information that can be used to continue to refine main extension programs and tariffs that best encourage consumers to extend natural gas service to their homes and businesses throughout Pennsylvania. As such, the OCA submits that the LCIP, as modified, is in the public interest as it should promote the expansion of natural gas without burdening the other ratepayers not participating or eligible for the program.

Appendix H

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2016-2529660**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

STATEMENT OF SMALL BUSINESS ADVOCATE IN SUPPORT OF SETTLEMENT

I. Introduction

The Office of Small Business Advocate ("OSBA") is an agency of the Commonwealth of Pennsylvania authorized by the Small Business Advocate Act (Act 181 of 1988, 73 P.S. §§ 399.41 – 399.50) to represent the interests of small business consumers as a party in proceedings before the Pennsylvania Public Utility Commission ("Commission").

On March 18, 2016, Columbia Gas of Pennsylvania, Inc. ("Columbia") filed with the Pennsylvania Public Utility Commission ("Commission") Supplement No. 241 to its Tariff Gas – Pa. P.U.C. No. 9 ("Supplement No. 241" or "base rate filing"). Supplement No. 241 proposed an increase in revenues of approximately $55.3 million which represented an 11.23% increase in operating revenues based on a future test year ending December 31, 2017.

On April 21, 2016, the Commission issued an Order suspending Columbia's Supplement No. 241 until December 19, 2016. The OSBA filed a Formal Complaint on April 4, 2016. Formal Complaints were also filed on behalf of the Office of Consumer Advocate, Columbia Industrial Intervenors ("CII"), the Pennsylvania State University ("PSU"), and several individual complainants. In addition, Petitions to Intervene were filed by the Natural Gas Supplier ("NGS") parties[1], the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), the Community Action Association of Pennsylvania ("CAAP") and Direct Energy. The Commission's Bureau of Investigation and Enforcement ("I&E") entered its appearance. These parties and intervenors are collectively referred to hereafter as "Joint Petitioners."

The initial Prehearing Conference was held as scheduled on April 28, 2016, during which the presiding officer, Administrative Law Judge ("ALJ") Katrina L. Dunderdale established the litigation schedule and discovery rules.

The Joint Petitioners conducted substantial formal and informal discovery in this proceeding. Pursuant to the established litigation schedule, the OSBA and other parties served their direct testimony on June 16, 2016, rebuttal testimony on July 13, 2016, and surrebuttal testimony On July 26, 2016,

The Joint Petitioners held numerous settlement discussions over the course of this proceeding. As a result of those discussions and the efforts of the Joint Petitioners, a settlement in principle was achieved by the Joint Petitioners.

On August 3, 2016, the ALJ held a hearing at which Columbia's filing, and the testimony and exhibits served by the parties during the course of the proceeding were formally introduced and admitted into the evidentiary record.

In the Settlement, the Joint Petitioners have proposed that rates be designed to produce an additional $35 million in annual base rate operating revenues instead of the Company's filed increase request of approximately $55.3 million. Upon approval of the Settlement, Columbia will receive an increase in existing overall base rates of approximately 7.12%, instead of the

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[1] The NGS parties consist of Dominion Retail, Inc., Shipley Energy Company, Interstate Gas Supply, Inc., and AMERIGreen Energy.

11.23% increase proposed in Columbia's filing.

II. Summary of the OSBA's Principal Concerns

As is its usual practice, the OSBA focused on the issues of cost allocation, revenue allocation, and rate design.

With respect to cost allocation, the Company submitted two alternative methods for allocating costs, which produced widely varying results. The OCA also submitted a cost allocation study, which produced even more disparate results. In the OSBA's view, none of these cost allocation methods are consistent with relatively recent Commission rulings regarding gas distribution cost allocation studies. Moreover, in the OSBA's view, gas distribution utilities should begin to develop more innovative methods for allocating costs, as the traditional approaches are theoretically suspect and not particularly practical given the wide range of results. As it is impossible for an outsider to undertake such an approach without the full support and cooperation of the Company, the OSBA did not prepare an independent alternative to the Company's cost allocation studies in this proceeding. As part of the OSBA review, however, OSBA witness Mr. Knecht did identify and correct what appeared to be an inadvertent error in the Company's cost allocation model. The Company subsequently acknowledged and corrected this error.

OSBA developed a revenue allocation calculation designed to move rates much closer to allocated costs, with costs being based on a subjectively weighted average of the two Company cost allocation methods. While this approach was technically very different from the unweighed simple average approach that the Company claimed it was using, the numerical revenue allocation to the combined small and medium business classes ended up being quite similar to that actually proposed by the Company. As such, the OSBA's revenue allocation recommendation for those combined classes was little different from that of the Company. In contrast, however, the OCA and I&E offered revenue allocation proposals that would have substantially increased the revenues sought from these two rate classes.

Regarding rate design, consistent with OSBA's recommendation in last year's base rates proceeding, the Company bifurcated its cost allocation analysis for the heterogeneous SGSS/SCD/SGDS rate class, into customers above and below annual throughput of 644 Dth per year. Based on the customer cost analysis in OSBA's modified cost allocation studies, the OSBA concluded that the Company's proposed increase to the customer charge for the larger rate class group was not supported by costs, and that no increase should be applied.

III. Settlement

This Settlement sets forth a comprehensive list of issues which were resolved through the negotiation process. The OSBA does not object to the resolution of any of those issues as detailed in the text of the Settlement.

Specifically, the issues listed above and in OSBA's testimony were resolved to the OSBA's satisfaction in the Settlement.

Regarding cost allocation, the Settlement takes no position on the appropriate methodology for cost allocation. The revenue allocation and rate design values developed in the Settlement represent a "black box" settlement. As the OSBA believes a new method should be developed for cost allocation, and because the methods in use in this proceeding produced enormously disparate results, the OSBA determined that there was no value in attempting to "lock in" a specific cost allocation methodology at this time. Thus, settling this case without reaching a decision on a cost allocation method represented OSBA's preferred result.

Regarding revenue allocation, the Settlement values in Appendix A generally lie within the range of recommendations from the parties. A comparison of the Settlement with the parties' litigation positions is shown in the table below. As shown, the Settlement lies well within the range of positions.

Revenue Allocation Review					
Class	Columbia	OSBA	OCA	I&E	Settlement
RS/RDS	78.2%	78.5%	58.3%	64.3%	74.0%
SGS1	7.7%	12.2%	11.3%	10.9%	8.3%
SGS2	6.8%	2.5%	17.7%	13.2%	9.4%
SDS/LGSS	3.3%	1.6%	8.4%	6.2%	5.1%
LDS/LGSS	3.9%	5.2%	4.0%	5.4%	3.1%
MDS	0.0%	0.0%	0.4%	0.0%	0.0%
Total	100.0%	100.0%	100.0%	100.0%	100.0%

In recognition of the wide range of cost allocation results and revenue allocation positions of the parties, the OSBA deems the values in Appendix A of the Settlement to represent a reasonable compromise

Finally, consistent with the OSBA's position, the Settlement specifies that no increase be applied to the customer charge for either small business rate class. This aspect of the Settlement thereby fully resolves OSBA's concern in this respect..

As the OSBA's issues of principal concern were resolved through the Settlement, agreeing to the text of this Settlement enables the OSBA to conserve its resources and avoid the uncertainties inherent in fully litigating the case.

WHEREFORE, the OSBA respectfully requests that the Administrative Law Judge and the Commission approve the text of this Settlement without modification.

Respectfully submitted,

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Dated: September 5, 2014

Appendix I

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	R-2016-2529660
Office of Consumer Advocate	:	C-2016-2535301
Office of Small Business Advocate	:	C-2016-2538051
Columbia Industrial Intervenors	:	C-2016-2541753
Pennsylvania State University	:	C-2016-2541623
Ralph Miller	:	C-2016-2538611
Michael Pikus	:	C-2016-2538843
Richard Collins	:	C-2016-2547479
James Testrake	:	C-2016-2555931
	:	
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

STATEMENT IN SUPPORT OF THE
COLUMBIA INDUSTRIAL INTERVENORS

TO ADMINISTRATIVE LAW JUDGE KATRINA L. DUNDERDALE:

I. INTRODUCTION

The Columbia Industrial Intervenors ("CII")[1], by and through its counsel, submit that the Joint Petition for Settlement ("Joint Petition" or "Settlement"), filed in the above-captioned proceeding with the Pennsylvania Public Utility Commission ("PUC" or "Commission"), reflects a settlement among the Joint Petitioners with respect to Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or "Company"), March 18, 2016, filing of Supplement No. 241 to Tariff Gas – Pa. P.U.C. No. 9, which sought to increase Columbia's total annual operating revenues by approximately $55.3 million. As a result of settlement discussions, Columbia, CII, the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), the PUC's Bureau of Investigation and Enforcement ("I&E"), Dominion Retail, Inc. ("Dominion"), Shipley

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[1] CII's members for purposes of this proceeding are Glen-Gery Corporation and Knouse Foods Cooperative, Inc.

Energy Company ("Shipley"), Interstate Gas Supply, Inc. ("IGS") and AMERIGreen Energy ("AMERIGreen"),[2] Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), Community Action Association of Pennsylvania ("CAAP"), The Pennsylvania State University ("PSU"), Direct Energy Business, LLC, Direct Energy Services, LLC, and Direct Energy Business Marketing, LLC (collectively, "Direct Energy") (collectively, "Parties" or "Joint Petitioners") have agreed upon the terms embodied in the Joint Petition filed by Columbia.

The Joint Petitioners have agreed to a settlement of all issues in the above-captioned general base rate proceeding (the "2016 Base Rate Filing"). Among other issues, the Settlement provides for increases in rates designed to produce $35 million in additional base rate revenue, based upon the pro forma level of operations for the twelve months ending on December 31, 2017. CII offers this Statement in Support to further demonstrate that the Settlement is in the public interest and should be approved without modification.

II. BACKGROUND

1. On March 18, 2016, Columbia filed Supplement No. 241 to its Tariff Gas – Pa. P.U.C. No. 9, which contained proposed changes in rates, rules, and regulations calculated to produce approximately $55.3 million, or an increase of 11.23%, in additional operating revenues based upon a pro forma fully projected future test year ("FPFTY") ending December 31, 2017.

2. On April 25, 2016, CII submitted a Complaint at Docket No. C-2016-2541753. As noted in Paragraph 5 of CII's Complaint, CII members receive service from Columbia under both sales and transportation rate schedules. Because CII members use substantial volumes of natural gas in their manufacturing and operational processes, natural gas costs comprise a significant

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2 For purposes of this Settlement, Dominion, Shipley, IGS and AMERIGreen are referred to collectively as the NGS Parties.

element of their operational costs. As a result, CII members were concerned that the proposed increase may have an adverse impact upon their operational processes and business costs.

3. A Prehearing Conference was held on April 28, 2016, before presiding Administrative Law Judge ("ALJ") Katrina L. Dunderdale, at which time the procedural schedule was established. Pursuant to that Schedule, CII submitted the following: (1) CII Statement No. 1, Direct Testimony of Frank Plank; (2) CII Statement No. 1-R, Rebuttal Testimony of Frank Plank; and (3) CII Statement No. 1-S, Surrebuttal Testimony of Frank Plank. Specifically, CII responded to Columbia's and other parties' proposed cost allocations to the Large Distribution Service ("LDS") rate class to the extent these allocations did not account for the fact that Rate Schedule LDS includes customers on both the tariff rate (*e.g.*, "non-flex rate customers") and on negotiated, or "flexed" rates (*e.g.*, "flex rate customers"). Although only non-flex customers would be subject to any rate increase assigned to Rate Schedule LDS, "several of the parties' proposed rate allocations did not accurately reflect the fact that non-flex LDS customers would receive a significantly higher increase than the Company's stated overall base rate increase for the LDS rate class. "

4. On July 28, 2016, the parties informed ALJ Dunderdale that a partial settlement had been reached and requested that the first day of the evidentiary hearing be canceled to allow additional time for settlement negotiations on the remaining issues.

5. On August 3, 2016, ALJ Dunderdale held an evidentiary hearing for the purpose of submitting testimony and exhibits into the record. At the evidentiary hearing, the parties waived cross-examination of all witnesses.

6. During the course of this proceeding, the Joint Petitioners held numerous settlement discussions resulting in an agreement to settle all issues.

III. STATEMENT IN SUPPORT OF SETTLEMENT

7. The Commission has a strong policy favoring settlements, and "encourages parties to seek negotiated settlements of contested proceedings in lieu of incurring the time, expense and uncertainty of litigation." 52 Pa. Code § 69.391; *see also* 52 Pa. Code § 5.231. As a result of the efforts and discussions held among the parties to this proceeding, the Joint Petitioners have reached a settlement of all issues. The Joint Petitioners agree that approval of the proposed Settlement is in the best interest of the parties involved.

A. REVENUE REQUIREMENT

8. Under the Settlement, rates will be designed to produce an increase in operating revenues of $35 million based upon the pro forma level of operations for the twelve months ending on December 31, 2017. The Joint Petitioners agree that this approximate $35 million rate increase achieved in the Joint Petition is just, reasonable, and in the public interest.

B. REVENUE ALLOCATION AND RATE DESIGN

9. The Joint Petitioners agree that the $35 million rate increase should be allocated pursuant to the terms of the Settlement. The Joint Petitioners agree that the rate design for all rate classes shall be set forth as provided in Appendix B of the Joint Petition. The Joint Petitioners acknowledge that revenue allocation and rate design outcomes reflect a compromise and do not endorse any particular cost of service study.

10. The Joint Petitioners agree that the Company should be authorized to file a tariff supplement containing the rates set forth in Appendix B of the Joint Petition.

C. UNIVERSAL SERVICE AND CONSERVATION

11. The Joint Petitioners agree to the settlement terms in the Joint Petition regarding Universal Service and Conservation.

D. PROGRAMS TO EXPAND THE AVAILABILITY OF GAS SERVICE

12. The Joint Petitioners agree to the settlement terms in the Joint Petition regarding the Company's proposal to expand the availability of gas service.

E. NATURAL GAS SUPPLIER ISSUES

13. The Joint Petitioners[3] agree to the settlement terms in the Joint Petition regarding natural gas supplier issues.

F. OTHER

14. The Joint Petitioners agree to the settlement terms set forth in paragraphs 58-59 of the Joint Petition regarding other issues, such as Columbia's efforts to reduce restoration costs. The Joint Petitioners agree that the Company's proposed tariff revisions, except as otherwise modified by the Settlement, are approved.

IV. SETTLEMENT IS IN THE PUBLIC INTEREST

15. The Joint Petitioners achieved this Settlement after an extensive investigation of Columbia's filing, including informal and formal discovery and the submission of Direct, Rebuttal, and Surrebuttal testimony.

16. The Joint Petition is in the public interest for the following reasons:

a. As a result of the Joint Petition, expenses incurred by the Joint Petitioners and the Commission for completing this proceeding will be less than they would have been if the proceeding had been fully litigated.

b. Uncertainties regarding further expenses associated with possible appeals from the Final Order of the Commission are avoided as a result of the Joint Petition.

c. The Joint Petition results in an increase in Columbia's rates by $35 million, which is approximately 63% of the Company's original request of $55.3 million.

[3] The OCA takes no position on the settlement terms regarding natural gas supplier issues as set forth in paragraphs 50-57 of the Settlement.

d. The Joint Petition provides a just and reasonable means by which to allocate the resulting increase.

e. The Joint Petition addresses issues regarding Natural Gas Supplier concerns, including establishing a revised penalty structure for non-compliance with Operational Flow Orders and Operational Maintenance Orders, as well as creating a collaborative to discuss new approaches to deal with on-going pipeline delivery constraints.

f. The Joint Petition reflects compromises on all sides presented without prejudice to any position any Joint Petitioner may have advanced so far in this proceeding. Similarly, the Joint Petition is presented without prejudice to any position any party may advance in future proceedings involving the Company.

17. In addition, the Joint Petition specifically satisfies the concerns of CII by: (1) lowering the revenue increase amount by approximately 37%; (2) reasonably allocating the proposed increase among the customer classes; and (3) creating a collaborative to discuss new approaches to dealing with on-going pipeline delivery constraints.

18. CII supports the Joint Petition because it is in the public interest; however, in the event the Joint Petition is rejected by the ALJ or the Commission, CII will resume its litigation position, which differs from the terms of the Joint Petition.

19. As set forth above, CII submits that the Settlement is in the public interest and adheres to Commission policies promoting negotiated settlements. Although Joint Petitioners have invested time and resources in the negotiation of the Joint Petition, this process has allowed the parties, and the Commission, to avoid expending the substantial resources that would have been required to fully litigate this proceeding while still reaching a just, reasonable, and non-discriminatory result. Joint Petitioners have thus reached an amicable solution to this dispute as embodied in the Settlement. Approval of the Settlement will permit the Commission and Joint Petitioners to avoid incurring the additional time, expense, and uncertainty of further current litigation of a number of major issues in this proceeding. *See* 52 Pa. Code § 69.391; 52 Pa. Code § 5.231.

V. CONDITIONS OF SETTLEMENT

20. The Joint Petitioners agree to the conditions of Settlement, as set forth in Paragraphs 63 to 70 in the Joint Petition.

WHEREFORE, the Columbia Industrial Intervenors respectfully request that the Administrative Law Judge and the Commission approve the Joint Petition for Settlement without modification.

Respectfully submitted,

McNEES WALLACE & NURICK LLC

By Kenneth R. Stark

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Counsel to the Columbia Industrial Intervenors

Dated: September 1, 2016

Appendix J

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2016-2529660
	:	
Columbia Gas of Pennsylvania, Inc.	:	

THE NATURAL GAS SUPPLIER PARTIES' STATEMENT IN SUPPORT OF SETTLEMENT

TO THE HONORABLE KATRINA L. DUNDERDALE:

AND NOW, come Dominion Retail, Inc. d/b/a Dominion Energy Solutions ("DES"), Interstate Gas Supply, Inc. d/b/a IGS Energy ("IGS"), Shipley Choice LLC d/b/a Shipley Energy ("Shipley") and AMERIGreen Energy ("AMERIGreen") (collectively "the NGS Parties"), and hereby submit their Statement in Support of the Joint Petition for Settlement ("Settlement") being filed simultaneously herewith. The NGS Parties respectfully submit that the settlement is in the public interest and should be approved by the Pennsylvania Public Utility Commission ("Commission") as presented. In support thereof, the NGS Parties state as follows:

I. BACKGROUND

1. On or about March 18, 2016, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") filed Supplement No. 241 to its tariff gas P.U.C. No. 9 ("Supplement No. 241") seeking to increase operating revenues by approximately $46.2 million, or by approximately 8.63%. By Order dated April 21, 2016, the Commission suspended the effective date of the tariff until December 19, 2016.

2. The NGS Parties filed their Petition to Intervene in the above-captioned matter on April 6, 2016, which Petition was granted by the Presiding Administrative Law Judge at the prehearing conference which was held Thursday, April 28, 2016.

3. In their Prehearing Conference Memorandum, the NGS Parties identified a number of issues that it intended to address in its testimony in this matter, including Columbia's proposed change with regard to distribution nominations in Section 2.7.2 of its tariff which identified actions that Columbia may take in order to comply with upstream pipeline restrictions and a similar required regarding CHOICE in Section 4.9.5 of its tariff; and, the need for natural gas suppliers to include an enrollment type (telephone, internet, and/or in writing) when enrolling a customer (proposed tariff Section 4.6.5). Mr. Cusati, the NGS Parties' witness, addressed these issues in his testimony.

4. On April 25, 2016, Direct Energy, also a natural gas supplier, filed its own petition to intervene which also was granted. Direct Energy's witness, Mr. Magnani, identified additional issues as being problematic as well. These include: the application process, which he contended is extensive and redundant, particularly when customers switch suppliers, because Columbia requires the same information be provided multiple times and including the process requirement that customers sign into Columbia's aviator system and assign privileges to all parties involved in a transaction to allow them to review customer information. Mr. Magnani also described deficiencies in Columbia's data systems which make supplier compliance with operational flow orders ("OFO") or operational matching orders ("OMO") more difficult. Finally, Mr. Magnani addressed the penalty structure on Columbia's system and the excessive penalties that can be charged during non-OFO or OMO periods.

5. As part of the settlement process, the NGS Parties and Direct Energy presented a unified settlement proposal to Columbia so as to seek uniform resolution of all issues related to natural gas supplier issues. The Joint Petition for Settlement proposes to resolve, in some fashion, all of the issues presented by the NGS Parties and/or Direct Energy.

II. THE SETTLEMENT

6. The NGS Parties take no position on settlement paragraphs 24-50 and 58.

7. Columbia has agreed to remove the designation of enrollment type from the customer submission procedure (Settlement ¶ 50). This will eliminate the need for NGS' to modify their data systems to collect and transmit this information to Columbia, and will eliminate the precarious activity, in the eyes of NGS's, of providing marketing information to an entity that views itself as a competitor.

8. Columbia has agreed to modify its existing customer application process for customers when they are switching natural gas suppliers to use a shortened form of that process. In particular:

> Columbia agrees to utilize pages 4 and 5 of the existing customer application, plus an additional page requiring updated contact information (emergency, billing and mailing), as a shortened version of the agency form for GDS customers who seek to change their NGS supplier (as further modified per paragraph 52, below). This shortened agency form shall be effective for contracts rendered on or after thirty (30) days after the entry of the Commission Order approving this Settlement. (Settlement ¶ 51.).

This change will allow for smoother signups for commercial customers and should lessen the current barrier that some customers experience in moving to the competitive market – the headache of completing numerous redundant forms.

9. Columbia has also agreed that as soon as possible, and in no event later than six months following approval of the settlement, it will modify the forms and its aviator agreement

to allow that a supplier beginning to serve a new customer will have immediate access to the customer's information in the aviator system without Columbia being required to ask the customer to make the changes. (Settlement ¶ 52). This change also simplifies and smooths out the enrollment process for commercial customers. It will eliminate the need for the customer to sign in to the Aviator system every time they make a change in supplier to change the permissions, and will instead provide suppliers with the opportunity to provide excellent customer service and manage these tasks for their customers.

10. Columbia also agreed to modify the penalty structure for non-compliance with OFO and OMO and other penalties to reflect a market-based structure, using an index-based formula rather than an arbitrary, and non-market sensitive amount. (Settlement ¶ 53). The revised penalty structure, for non-compliance with Operational Flow Orders ("OFOs") and Operational Matching Orders ("OMOs"), as well as the non-compliance charges related to CHOICE deliveries, will impose a penalty at 3 times the highest of the midpoint prices reflected in Platts Gas Daily for the day of the OMO or OFO non-compliance, from the applicable indices, depending upon the market area utilized. In the event no midpoint prices are published in Platts Gas Daily on a particular day, the highest price paid by Columbia on that day shall be used as the index price. Columbia will be required to update the applicable indices on 60 days' notice to Customer Proxies in the event of a change in applicable indices. This change will produce more sensible penalty amounts while still providing more than sufficient incentive for suppliers to meet their delivery obligation.

11. Columbia has proposed to require commercial customers and other large customers to have the equipment necessary for daily meter reads and to allow for recovery of the costs of installing that equipment. (Settlement ¶ 54). In particular, customers eligible to be

served on Rate Schedules SDS, LDS and MLDS [Small Distribution Service, Large Distribution Service, and Main Line Distribution Service] will be required to have Electronic Flow Correctors ("EFC") and telephonic equipment to transmit daily usage information to Columbia. Columbia will install, own, operate and maintain the equipment, including telephonic or similar technology, so long as Columbia is able to recover the prudent capital and operating and maintenance costs. Hand in glove with the installation of the equipment is Columbia's agreement to provide the meter read information on a daily basis, by 1:00 PM the following day. The current lack of information for suppliers is a root cause of many problems, not the least of which is projecting customer needs in real time and ensuring adequate amounts of gas are delivered to the city gate. This breakthrough will allow suppliers more data and more flexibility in providing service. In furtherance of these provisions and once these provisions are approved, Columbia has also agreed to modify OMO/OFO penalties for suppliers with respect to any OMO customer with an EFC and operating telephone equipment for which Columbia does not have daily usage data available by the end of an OMO Period. (Settlement ¶ 55).

12. Columbia has agreed to withdraw its proposed Section 2.7.2 to its rules applicable to distribution service ("RADS") and to hold a collaborative that will address, *inter alia*, issues surrounding CHOICE customers under RADS Section 4.9.5 and ways to increase transparency in provision of Choice service. Specifically, the collaborative will provide a forum to discuss new approaches to deal with ongoing pipeline delivery constraints, including the creation of new market "orders." (Settlement at ¶¶ 56-57). The Collaborative will span 120 days unless extended by consensus of the parties participating. Any resolutions requiring tariff changes shall be reflected in a proposed non-general tariff filing by Columbia at the conclusion of the collaborative. Without limitation of the issues, the parties will at a minimum, address how

transparency may be achieved as to Columbia's nominations to alternate delivery points under RADS Section 4.9.5, including information that Columbia could share with suppliers regarding actual nominations. At the conclusion of the collaborative, Columbia will file a letter report with the Commission summarizing the results and consensus recommendations of the collaborative.

III. THE SETTLEMENT IS IN THE PUBLIC INTEREST.

13. The NGS Parties submit that the Settlement is in the public interest and should be approved without modification. It has satisfactorily addressed the deficiencies identified by all the Natural Gas Suppliers that participated in the proceeding and represents the first rate case in recent memory where the parties did not clash over the appropriate level of the GPC. The penalty structure changes, while seemingly nominal, when coupled with other operational changes including increased access to customer usage information, will serve to further reduce the risk of unintentional mis-deliveries. Moreover, the changes to the various business practices will reduce the complexity and associated costs of serving customers on the Columbia system and will allow suppliers to provide better value for customers.

14. For all of these reasons, and because this case has been resolved in an acceptable fashion without the need for litigation and the incurrence of additional costs, the NGS Parties believe that this Settlement is in the public interest and is just and reasonable. The NGS Parties accordingly submit that it should be approved as presented.

Respectfully submitted,

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Dated: September 1, 2016

Appendix K

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2016-2529660
	:	
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

STATEMENT OF THE COALITION FOR AFFORDABLE UTILITY SERVICES AND ENERGY EFFICIENCY IN PENNSYLVANIA (CAUSE-PA) IN SUPPORT OF JOINT PETITION FOR SETTLEMENT

The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), one of the signatory parties to the Joint Petition for Settlement ("Joint Petition" or "Settlement"), respectfully requests that the terms and conditions of the Settlement be approved by the Honorable Katrina L. Dunderdale, Administrative Law Judge, and the Pennsylvania Public Utility Commission ("Commission"). For the reasons stated more fully below, CAUSE-PA believes that the terms and conditions of the Settlement are in the public interest.

I. INTRODUCTION

CAUSE-PA intervened in this proceeding to address, among other issues, whether the proposed rate increase would detrimentally impact the ability of Columbia Gas of Pennsylvania, Inc.'s ("Columbia") low-income customers to afford service under reasonable terms and conditions.

In short, the Settlement provides several provisions which address CAUSE-PA's overarching concern. In relevant part, the Settlement provides that the fixed charge portion of the residential rate structure will remain unchanged, ensuring that low income / low usage households do not bear a disproportionate share of the rate increase. It also provides that Columbia will continue funding its Hardship Fund program at current levels with pipeline penalty credit funds and refunds received through February 28, 2018, and that Columbia will take concrete steps to increase voluntary donations to the programs. Finally, the Settlement strengthens outreach efforts by expanding the third party notification system to allow CAP participants to designate a community based organization (CBO) to receive notices about the customer's account, and through increased distribution of universal service program brochures at non-utility locations.

While it does not address all of CAUSE-PA's concerns and recommendations, the Settlement was arrived at through good faith negotiation by all parties, and is in the public interest in that it addresses a number of the most critical issues of concern to CAUSE-PA in this proceeding, balances the interests of the parties, and resolves a number of important issues fairly. Considerable litigation and associated costs will be avoided; and if approved, the Settlement will eliminate the possibility of further litigation and appeals, along with their attendant costs.

II. BACKGROUND

CAUSE-PA adopts the background as set forth in Paragraphs 1-21 of the Joint Petition.

III. CAUSE-PA'S REASONS FOR SUPPORT OF THE SETTLEMENT

The following terms of this Settlement reflect a carefully balanced compromise of the interests of all the Joint Petitioners in this proceeding:

- Paragraph 38 confirms that the fixed residential customer charge will remain at the current $16.75, without increase. This provision is critical to ensure that the burden of a rate increase does not disproportionately fall on low and fixed income residents – and in particular, disabled and elderly low and fixed income populations – who use less energy on average than their non-low income counterparts and, thus, will be disproportionately impacted by a sharp increase in fixed charges. (OCA St. 4, Colton, at 12-14). It also ensures that the rate structure does not undermine ratepayer investments in energy efficiency and weatherization through the Low Income Usage Reduction Program (LIURP), which is designed to reduce low income household usage and, in turn, reduce the energy burden for low income customers. (See OCA St. 4, Colton, at 19:22-20:1).

- Paragraph 42 confirms that LIURP funding will remain unchanged until the expiration of a settlement agreement in a previous base rate proceeding (Docket R-2014-2406274). It further provides that unspent LIURP funds will be carried over and added to the following years' funding. This clarification of LIURP budgeting will help ensure that the LIURP is operated at full capacity to achieve energy and bill savings for low income customers.

- Paragraph 44 provides that Columbia will extend its Third Party Notification program to include CAP reminder notices – including CAP removal. Columbia also agreed to make the notification forms available through CBOs, and to encourage CBOs to discuss third party notification with customers and include the forms in processing applications for assistance. This Settlement provision is explicit that the customer's participation in the Third Party Notification program must be completely voluntary.

  These enhancements to the Third Party Notification program are designed to address, in small part, the significant and persistent decline in Columbia's CAP enrollment, which is largely attributable to the rising number of CAP customers who default from the program. (CAUSE-PA St. 1-R, Geller, at 10; OCA St. 4, Colton, at 22-24). The decline has caused a ripple effect on low income arrearages – with a nearly two fold increase in the percentage of low-income dollars from 2010 to 2014. (OCA St. 4, Colton, at 23). Terminations and reconnections have also suffered, all while federal heating assistance through LIHEAP declines. (OCA St. 4, Colton, at 24-25; CAUSE-PA St. 1-R, Geller, at 10).

As a remedy to this "disturbing trend", Roger Colton, expert witness for the Office of Consumer Advocate, suggested using the Third Party Notification program to allow CBOs to receive notice of pending CAP defaults, which would allow CBOs to perform targeted outreach to these customers. In response to this proposal, Mr. Harry Geller, expert witness for CAUSE-PA, raised concerns, explaining that the notification system must be completely voluntary, that systems must be in place to ensure customers provided knowing and voluntary consent, that it not replace current customer notification methods, and that care is taken to ensure that customer confidentiality and privacy are protected. (CAUSE-PA St. 1-R at 11-12).

The provision included in the Settlement addresses Mr. Geller's concerns that the program be voluntary to protect customer privacy. While CAUSE-PA believes that this provision is insufficient to fully remedy the troubling decline in CAP enrollment (and the resulting rise in low income arrears and terminations and decline in reconnections), CAUSE-PA nonetheless asserts that use of the third party notification system is a step in the right direction, and supports its implementation.

- Paragraph 45 provides that Columbia will provide brochures for all of its universal service programs to non-utility access points, including CBOs. As with the expanded third party notification program, this enhanced outreach will help ensure that low income populations are better informed about the availability of Columbia's various assistance programs.

CAUSE-PA notes again that, while its positions have not been fully adopted, the Settlement was arrived at through good faith negotiation by all parties and represents a fair and balanced resolution of a number of important issues. Thus, when taken together, the provisions of this settlement are in the public interest, and should be approved by the Commission in full.

IV. CONCLUSION

CAUSE-PA submits that the Settlement, which was achieved by the Joint Petitioners after an extensive investigation of Columbia's filing, is in the public interest. Acceptance of the Settlement avoids the necessity of further administrative and possible appellate proceedings regarding the settled issues at a substantial cost to the Joint Petitioners and Columbia's customers. Accordingly, CAUSE-PA respectfully requests that ALJ Long and the Commission approve the Settlement.

PENNSYLVANIA UTILITY LAW PROJECT
On Behalf of CAUSE-PA

Date: September 1, 2016

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Appendix L

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2016-2529660
Office of Consumer Advocate	:	C-2016-2535301
Office of Small Business Advocate	:	C-2016-2538051
Columbia Industrial Intervenors	:	C-2016-2541753
Pennsylvania State University	:	C-2016-2541623
Ralph Miller	:	C-2016-2538611
Michael Pikus	:	C-2016-2538843
Richard Collins	:	C-2016-2547479
James Testrake	:	C-2016-2555931
	:	
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.		

COMMUNITY ACTION ASSOCIATION OF PENNSYLVANIA'S STATEMENT IN SUPPORT OF JOINT PETITION FOR SETTLEMENT

NOW COMES the Intervener, the Community Action Association of Pennsylvania (CAAP) and files this Statement in Support of the Joint Petition for Settlement in the above-captioned matter and agrees to its terms based upon the following:

1. CAAP is a statewide association representing Pennsylvania's community action agencies that provide anti-poverty planning and community development activities for low-income communities and services to individuals and families.

2. CAAP intervened in the above-captioned matter to address the adequacy of the Company's programs for its low-income customers and the effect of any proposed rate increase or change in rate structure on those programs and customers.

3. CAAP supports the Joint Petition for Settlement and believes that it is in compliance with the applicable laws and regulations and serves the public interest based upon the following:

A. The Settlement maintains adequate funding for the Company's LIURP program and ensures the carry-over of unused funds in a given year to the following year and that will help low-income customers deal with the effect of the rate increase resulting from this Settlement;

B. In the Settlement the Company reiterates its intent to continue to use community-based organizations to assist in the implementation of its universal service programs;

C. The Company proposed in its initial filing to increase the fixed monthly residential customer charge from $16.75 to $19.51. Such an increase in the fixed charge would have lessened the motive and ability of the residential class to conserve energy and reduce their monthly bill. The Settlement provides that the fixed monthly residential customer charge will remain at $16.75.

D. The settlement is consistent with the Commission's obligation under the Natural Gas Choice and Competition Act to insure that universal service programs are appropriately funded and available, that energy conservation measures are promoted and available to consumers, particularly low income consumers, and that community-based organizations are used to assist in the implementation of an electric company's universal service programs.

Respectfully submitted,

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Appendix M

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos.	R-2016-2529660
Office of Consumer Advocate	:		
Office of Small Business Advocate	:		C-2016-2535301
Columbia Industrial Intervenors	:		C-2016-2538051
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Michael Pikus	:		C-2016-2538611
Richard Collins	:		C-2016-2538843
James Testrake	:		C-2016-2547479
	:		C-2016-2555931
v.	:		
	:		
Columbia Gas of Pennsylvania, Inc.	:		
	:		

STATEMENT OF
THE PENNSYLVANIA STATE UNIVERSITY
IN SUPPORT OF
THE JOINT PETITION FOR SETTLEMENT

The Pennsylvania State University ("PSU") submits this Statement in Support of the Joint Petition for Settlement (the "Joint Petition") filed by the Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission (the "Commission"), the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), Columbia Industrial Intervenors ("CII"),[1] Dominion Retail, Inc. ("Dominion"), Shipley Energy Company ("Shipley"), Interstate Gas Supply, Inc. ("IGS") and AMERIGreen Energy ("AMERIGreen"),[2] Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"),

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[1] CII's member for purposes of this proceeding is Glen-Gery Corporation.

[2] For purposes of the Joint Petition and the Settlement, Dominion, Shipley, IGS and AMERIGreen are referred to collectively as the NGS Parties.

Community Action Association of Pennsylvania ("CAAP"), Direct Energy Business, LLC, Direct Energy Services, LLC, and Direct Energy Business Marketing, LLC (collectively, "Direct Energy"), Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"), and PSU (collectively, the "Joint Petitioners"). As indicated in the Joint Petition, the proposed settlement (the "Settlement") resolves all issues in the proceeding. Accordingly, and as discussed more fully below, PSU offers its support for the Settlement and requests that the Presiding Administrative Law Judge and the Commission grant the Joint Petition and approve the Settlement as submitted and without modification. In support thereof, PSU avers as follows:

1. On March 18, 2016, Columbia filed with the Commission Supplement No. 241 to its Tariff Gas – Pa. P.U.C. No. 9 ("Supplement No. 241" or "base rate filing"). Supplement No. 241, issued March 18, 2016 and to be effective May 17, 2016, proposed an increase in revenues of approximately $55.3 million which represents an 11.23% increase in operating revenues based upon a pro forma fully projected future test year ("FPFTY") ending December 31, 2017.

2. PSU is a major customer of Columbia for natural gas service with a number of separate accounts. PSU primarily takes service as a member of the Large Distribution Service/Large General Sales Service ("LDS/LGSS") customer classes, but it also takes service under the Small Distribution Service ("SDS"), Small General Sales Service ("SGSS"), and Residential Sales Service ("RSS") classes.

3. The terms of the Settlement were reached after numerous hours of negotiations among the Joint Petitioners that included the subject of cost of service studies and the allocation of the overall increase among the various rate classes and, in particular, to the LDS/LGSS rate classes.

4. In the Settlement, the Joint Petitioners have proposed that rates be designed to produce an additional $35 million in annual base rate operating revenues instead of the Company's filed increase request of $55.3 million. The increase for the LDS/LGSS classes is $1,100,000, which is less than the $1,380,000 million increase originally proposed by the Company.

5. While PSU continues to be concerned about attempts by certain parties to favor outdated cost of service methodologies that incorrectly treat customers or customer classes with superior load factors the same as customers or customer classes with poor load factors or fail to recognize the benefit of Flex service to all customers and allocated it as such, it supports the settlement as a compromise of competing positions that results in the rate of return of the LDS/LGSS class being closer to the system average rate of return than it would under the Company's original proposal. Movement of class rates of return to the system average rate of return is consistent with the requirement of *Lloyd vs. Pennsylvania Public Utility Commission*, 904 A.2d 1010 (Pa. Commw. Ct. 2006), that rate structures be gradually adjusted to move the class rate of return closer to the system average rate of return, thus causing rates to reflect the cost of providing service to each rate class and eliminating cross-subsidization.

6. PSU also supports the settlement because it satisfactorily resolves issues raised by natural gas suppliers as a compromise of competing positions.

7. PSU supports the Joint Petition because the Settlement is without prejudice or admission to any position any party, including PSU, may take in any subsequent or different proceeding. In addition, the Settlement will enable the parties to avoid the expenditure of significant additional time and expense that would have been necessary to fully litigate this proceeding to a conclusion. This will result in significant savings to all parties, as well as to Columbia's customers.

8. For all of these reasons, PSU submits that the Settlement is in the public interest and requests that the Commission approve the Settlement as presented in the Joint Petition for Settlement.

Respectfully submitted,

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DATED: September 2, 2016

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Appendix N

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2016-2529660
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	
	:	

DIRECT ENERGY'S
STATEMENT IN SUPPORT
OF THE
JOINT PETITION FOR SETTLEMENT

Direct Energy Services, LLC, and Direct Energy Business Marketing, LLC (collectively, "Direct Energy") offers this Statement In Support of the Joint Petition for Settlement ("Settlement") submitted by the Joint Petitioners.[1] Direct Energy supports approval of the Settlement[2] without modification and respectfully requests that Administrative Law Judge ("ALJ") Katrina L. Dunderdale and the Commission approve this settlement as in the public interest.

Direct Energy is an natural gas supplier ("NGS") licensed by the Commission to provide natural gas and related services to retail customers in Columbia's service territory.[3] Direct Energy's petition to intervene was granted,[4] and it submitted direct testimony, rebuttal

1 The following parties to the above-captioned proceedings are collectively referred to as the "Joint Petitioners": The Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"), Columbia Industrial Intervenors ("CII"), Dominion Retail, Inc. ("Dominion"), Shipley Energy Company ("Shipley"), Interstate Gas Supply, Inc. ("IGS") and AMERIGreen Energy ("AMERIGreen"), Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA"), Community Action Association of Pennsylvania ("CAAP"), The Pennsylvania State University ("PSU"), Direct Energy Business, LLC, Direct Energy and Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company").

2 Direct Energy takes no position with respect to the rate design set forth in Appendix "B" of the Settlement.

3 See PUC Docket Nos. A-125072 (Direct Energy Business, LLC), A-125135 (Direct Energy Services, LLC) and A-2013-2365792 (Direct Energy Business Marketing, LLC).

4 Prehearing Order dated April 29, 2016, at Ordering Paragraph 3.

testimony and surrebuttal testimony.[5]

In this proceeding, Direct Energy raised the following key issues and concerns: (1) the shortening of the paperwork required by customers to change suppliers; (2) the removal of barriers for NGSs to obtain a customer's usage information on the Columbia's Aviator system; (3) revisions to the calculation of penalties for over and under deliveries during Operational Flow Orders ("OFOs") or Operational Matching Orders ("OMOs") called by Columbia; (4) the recommendation that the new clause in Proposed Rules Applicable to Distribution Service ("RADS") 2.7.2 and 4.9.5 (Choice) which is related to Columbia's discretion to direct a supplier to schedule natural gas supplies from multiple delivery points – be more limited and defined; and (5) the need to improve the provision of customer usage data to suppliers in order to facilitate their ability to respond to OMOs.

As explained in greater detail below, the Settlement reasonably addresses Direct Energy's key issues and concerns and appropriately balances the sometimes competing concerns raised by various Joint Petitioners.

First, regarding the process of switching suppliers, the Settlement provides that Columbia will implement a shortened agency form.[6] This shortened form will reduce the prior burdensome process, which had a customer completing a five-page application every time that it switched suppliers. That five-page application asked for information that was not always readily available to the customer, and generated delays in the enrollment process.[7]

Second, regarding the customers' usage information, the Settlement provides that Columbia will implement new authorization forms to help ensure that NGSs are able to access

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5 Settlement at ¶ 10-12..

6 Settlement at ¶ 51.

7 Direct Energy St. 1 at 4; Direct Energy St. 1SR at 2-3.

all of their current customer's usage information on the Aviator system, or a comparable current or future system.[8] The existing authorization process required customers to login to the Aviator system with their master ID and decide who could see what data. This led to instances where NGSs did not always have continuous and reasonable access to customer usage data, which is needed to respond to OMOs and OFOs.[9]

Third, regarding penalty calculations, the Settlement provides that Columbia will adopt a gas index-based penalty structure.[10] The revised penalty will serve as an effective deterrent to behavior that may threaten operational integrity, while, at the same time, bear a more reasonable relationship to the operational conditions on the system. The prior penalty scheme gave equal treatment to all non-compliance, despite the fact that a warm weather OFO/OMO non-compliance does not threaten system reliability in the same way as cold weather OFO/OMO non-compliance.[11]

Fourth, regarding Columbia's discretion to direct a supplier to schedule natural gas supplies from multiple delivery points, the Settlement provides that RADS 2.7.2 shall be withdrawn, to be discussed as part of the collaborative.[12] That collaborative will discuss new approaches to deal with ongoing pipeline delivery constraints, including the creation of new market "orders." In addition, without limitation to other issues that may be addressed in the collaborative, the parties will address how transparency may be achieved as to Columbia's

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8 Settlement at ¶ 52.

9 Direct Energy St. 1 at 7-10; Direct Energy St. 1SR at 3-8.

10 Settlement at ¶ 53, 55.

11 Direct Energy St. 1 at 9-12 ;Direct Energy St. 1SR at 10-11.

12 Settlement at ¶ 56-57.

nominations to alternate delivery points under Section 4.9.5 (Choice), including information that Columbia could share with suppliers regarding actual nominations.

Fifth, Direct Energy had raised concerns about the timely availability of daily customer usage data in the "GTS0005 Reports and in the Aviator-EMDCS data base. The lack of such data had resulted in Direct Energy being unable to comply with certain OMOs and incurring substantial penalties. Columbia suggested that the lack of full data was attributable, at least in part, to malfunctioning or uninstalled Electronic Flow Correctors (EFCs) and functioning telephone equipment to transmit daily usage information to Columbia. In response to those concerns, Columbia agreed to propose to install, own, operate and maintain all equipment, including telephone or similar technology necessary to ensure the timely transmission of usage data from customer meters to Columbia, for subsequent display in the GTS0005 and Aviator-EMDCS data base. In addition, for customers with such facilities installed, Columbia agreed to use commercially reasonable efforts to display customer usage in the two relevant data bases by 1 PM on the day following the day for which the data is being provided. In addition, Columbia agreed that, in addition to any other remedy a supplier might have, if Columbia does not meet the 1PM/subsequent day deadline for any customer with an EFC and operating telephone equipment the penalty for non-compliance with an OMO is reduced by one-half.

On balance, the Settlement represents a fair balancing and compromise of the issues raised in this proceeding. Even though all of Direct Energy's concerns and issues are not fully addressed in the manner preferred by Direct Energy, the Settlement does represent improvements on many issues raised by Direct Energy and was developed as the result of the parties working cooperatively to reach a reasonable and comprehensive compromise of all the issues. In addition, the Settlement reduces the administrative burden and costs to resolve the numerous issues. For all these reasons, the Settlement is in the public interest and should be adopted.

Thus, Direct Energy respectfully requests that the Settlement be approved without modification.

Respectfully submitted,

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Date: September 1, 2016

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