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File #: 2270/148555

August 23, 2011

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

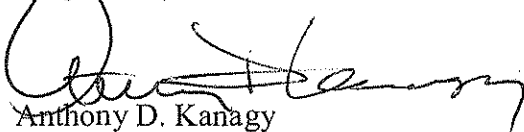
**RE: Pennsylvania Public Utility Commission, et al. v. UGI Central Penn Gas, Inc.
Docket No. R-2011-2238949, C-2011-2243177 and C-2011-2248231**

Dear Secretary Chiavetta:

Enclosed please find the Stipulation in Settlement of Section 1307(f) Rate Investigation for the above-referenced proceeding.

As indicated by the certificate of service, copies have been provided to the persons in the manner indicated.

Respectfully Submitted,



Anthony D. Kanagy

ADK/skr

Enclosures

cc: Honorable Kandace F. Melillo
Certificate of Service

CERTIFICATE OF SERVICE
(R-2011-2238949, C-2011-2243177 and C-2011-2248231)

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

VIA E-MAIL & FIRST CLASS MAIL

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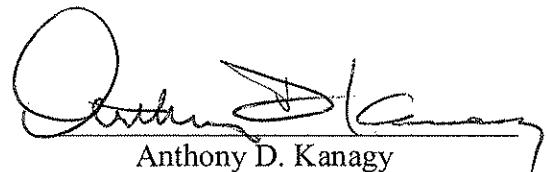
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Date: August 23, 2011


Anthony D. Kanagy

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY	:	
COMMISSION, ET AL.	:	
	:	Docket Nos. R-2011-2238949
v.	:	C-2011-2243177
	:	C-2011-2248231
UGI CENTRAL PENN GAS, INC.	:	

**STIPULATION IN SETTLEMENT OF
SECTION 1307(f) RATE INVESTIGATION**

TO ADMINISTRATIVE LAW JUDGE KANDACE F. MELILLO:

I. INTRODUCTION

UGI Central Penn Gas, Inc. ("CPG"), the Bureau of Investigation and Enforcement ("BI&E") of the Pennsylvania Public Utility Commission ("Commission"), the Office of Consumer Advocate ("OCA"), the Office of Small Business Advocate ("OSBA"),¹ CenterPoint Energy Services, Inc. ("CenterPoint"), Jerome H. Rhoads, Inc. d/b/a Rhoads Energy Corporation ("Rhoads"), and Shipley Energy Company with Shipley Choice LLC (collectively, "Shipley" and in combination with CenterPoint and Rhoads collectively the "Supplier Group"), parties in the above-captioned proceeding (hereinafter individually referred to as "Party" or collectively referred to as the "Parties"), hereby join in this Stipulation In Settlement Of Section 1307(f) Rate Investigation ("Settlement"),² and hereby request that Administrative Law Judge Kandace F. Melillo (the "ALJ") and the Commission:

¹ The OSBA takes no position on the capacity assignment provisions of the Settlement.

² In addition, the CPG Large Users Group ("CPGLUG"), the only other party in this proceeding, has

(1) authorize CPG to file a tariff supplement for service rendered on or after December 1, 2011, that implements, subject to updates and tariff modifications traditionally performed on December 1, the rates set forth in Appendix A hereto; and

(2) make all associated findings required by Section 1307(f) and Section 1318 of the Public Utility Code, 66 Pa.C.S. § 1307(f) and 66 Pa.C.S. § 1318.

The rates set forth in Appendix A reduce CPG's June 1, 2011 PGC rates of \$6.2704 per Dth applicable to Rate R (Residential Service) customers to \$6.2693 per Dth, or a reduction of \$0.0011 per Dth. The Appendix A rates also reduce CPG's June 1, 2011 PGC rate of \$6.2356 per Dth applicable to Rates G (General Service), RS (Resale Service) and O (Outdoor Lighting Service) customers to \$6.2345 per Dth, or a reduction of \$0.0011 per Dth.

Attached as Appendices D, E, F, G and H hereto are statements in support of the Settlement submitted by CPG, BI&E, OCA, OSBA and the Supplier Group. Attached as Appendix I is a letter from CPGLUG indicating that it neither supports nor opposes this Settlement.

II. BACKGROUND

In support of this Settlement, the Parties state as follows:

1. CPG is a natural gas distribution company with gross intrastate annual operating revenues in excess of \$40 million and is authorized by the provisions of Section 1307(f) of the Public Utility Code, and the Commission's gas cost recovery regulations at 52 Pa. Code §§ 53.61 - 53.68, to make annual purchased gas cost ("PGC") filings proposing gas rate modifications to reflect increases or decreases in its natural gas costs.

2. On April 29, 2011, CPG provided the Commission with the prefiling information required by 52 Pa. Code § 53.64(c) and 52 Pa. Code § 53.65.

indicated that it does not support or oppose the Settlement.

3. On or about May 3, 2011, the Office of Trial Staff (“OTS”) filed a Notice of Appearance.³

4. On or about May 11, 2011 the OCA filed a notice of appearance, formal complaint and public statement, docketed at C-2011-2243199, which CPG answered on June 3, 2011.

5. On June 1, 2011, in accordance with the schedule for Section 1307(f) filings established by the Commission, CPG submitted its 2011 PGC filing to the Commission, with proposed modifications to CPG’s Tariff Gas - Pa. P.U.C. No. 3 and 3S, to become effective December 1, 2011.

6. CPG’s June 1, 2011 PGC filing proposed to implement a PGC rate of \$6.27/Dth applicable to Rate R customers, and a PGC rate of \$6.24/Dth applicable to Rate G, RS and O customers, effective December 1, 2011.

7. CPG also filed the direct written testimony of its supporting witnesses with its PGC filing on June 1, 2011.

8. On June 7, 2011 PNG, CPG and UGI filed a petition for a Protective Order, and on June 15, 2011, filed a modified petition for a Protective Order.

9. On June 7, 2011, CPG supplemented its June 1, 2011 filing by filing certain additional pro forma tariff pages that had been inadvertently omitted from the June 1 filing.

10. On or about June 8, 2011, CPGLUG filed a petition to intervene that was granted during the prehearing conference conducted on June 16, 2011. Said intervention was confirmed in a subsequent Order issued by the ALJ on June 22, 2011.

11. On or about June 8, 2011 CenterPoint filed a petition to intervene.

³ The functions of OTS are now performed by the Commission’s Bureau of Investigation and Enforcement, a present signatory to this Stipulation in Settlement.

12. On or about June 13 and June 28, 2011 motions to admit Jason F. Leif *pro hac vice* to represent the various members of the Supplier Group were filed.

13. On or about June 14, 2011, the OSBA filed a notice of appearance, formal complaint and public statement, docketed at C-2011-2248231, which CPG answered on June 27, 2011.

14. In Orders issued by the ALJ on June 16 and June 29, 2011, the motions for admission *pro hac vice* were granted.

15. On June 16, 2011, a consolidated Prehearing Conference in the CPG, UGI Penn Natural Gas, Inc. ("PNG") PGC proceeding at Docket No. R-2011-2238943, and the UGI Utilities, Inc. – Gas Division ("UGI") PGC proceeding at Docket No. R-2011-2238953 was conducted by ALJ Melillo.

16. At the Prehearing Conference, amongst other things, the PNG, CPG and UGI PGC proceedings were consolidated by the ALJ for the limited purposes of hearing; a procedural schedule was adopted and certain discovery response rules were established.

17. By Order issued June 22, 2011, the ALJ granted the modified petition for a Protective Order.

18. Also, in an Order dated June 22, 2011, the petition to intervene of CenterPoint was granted.

19. On or about June 28, 2011 Shipley filed a petition to intervene.

20. On or about June 28, 2011 Rhoads filed a petition to intervene.

21. In an Order dated June 29, 2011 the petitions to intervene of Shipley and Rhoads were granted.

22. In accordance with the procedural schedule established by the ALJ, the OCA, OTS and the Supplier Group filed written direct testimony on July 11, 2011: CPG, OCA, OTS, OSBA and the Supplier Group filed rebuttal testimony on July 25, 2011, and CPG and the Supplier Group filed surrebuttal testimony on August 3, 2011.

23. Throughout this proceeding, all active parties explored the possibility of settlement in accordance with the Commission's Rules of Practice at 52 Pa. Code § 5.231.

24. On August 5, 2011 CPG notified the ALJ that an agreement in principle of all issues in each of the PNG, CPG and UGI PGC proceedings had been reached and requested a suspension of the procedural schedule.

25. By Order issued August 5, 2011, the ALJ suspended the procedural schedule, but made provision for the conduct of the previously scheduled hearing on August 8, 2011, for the admission of each parties' testimony and exhibits into the record by stipulation at each of the three consolidated dockets.

26. During the August 8, 2011, hearing, all of the testimony and exhibits filed in the case, with the exception of Supplier Group Exhibit SG-R5, were offered and admitted into the record by stipulation with accompanying signed affidavits or affirmations of the sponsoring witnesses.

III. GENERAL PROVISIONS OF SETTLEMENT

27. The Parties agree the rates for the recovery of the purchased gas costs of CPG should be revised effective December 1, 2011, subject to updates, to reflect the rates set forth in Appendix A hereto.

28. In its PGC compliance filing in this proceeding CPG will reflect 50,000 Dth of annual projected Customer Choice volumes subject to the Migration Rider for the PGC Year

beginning December 1, 2011, and will derive its E-Factor and Migration Rider using this 50,000 Dth projection.

29. CPG will continue to reflect updated annual Customer Choice volumes projected to be subject to the Migration Rider in the "S Factor – Projected Sales" component in its future annual PGC filings.

30. CPG will maintain the peak day demand numbers as filed in its April 29, 2011 Book I filing for the 2011-2012 winter season.

31. CPG will modify the design cold temperatures as shown in Appendix B.

32. In calculating the design day requirements for days other than the coldest day, CPG will perform a statistical analysis for each day using weather data for a thirty year period, updated every five years.

33. Based on the updated design cold temperatures, CPG will revise its proposed request-for-proposal ("RFP") for peaking service on its northern system, as initially described in CPG Statement No. 2, to request an 11 day, as opposed to a 9 day, service at a 100% load factor. The daily quantity requested in the RFP will remain 9,221 Dth for the winter of 2011-2012.

34. With respect to CPG's proposed RFP to seek a replacement for Texas Eastern capacity, initially described in CPG Statement No. 2, if CPG proposes to replace this capacity with a no-notice service, it will be required to demonstrate through the RFP process that No-Notice service is the lowest cost option, including reasonably expected off-system margins and capacity release revenues that would result from the availability of the No Notice Service. To evaluate the costs of replacement options for the Texas Eastern capacity, CPG will conduct RFPs for a minimum of two services. One RFP will be a no-notice service as described in CPG Statement No. 2, but CPG will revise this RFP from a 10 day to a 5 day service at a 100% load

factor. A second RFP will be for a 15 day day-ahead peaking service at a 100 percent load factor that will be nominated during the normal Intercontinental Exchange ("ICE") trading period (for example, CPG would nominate the service on Friday morning between 9:00 AM and 9:30 AM for ratable delivery over the period Saturday, Sunday and Monday). The maximum daily quantity for the Texas eastern replacement services (whether the replacement services or some portion thereof are No Notice services) will be 5,700 Dth for a five year term beginning with the 2012-2013 winter season. In these RFPs potential bidders will be provided four, as opposed to the initially proposed three, weeks to respond. All Parties reserve all rights to challenge the Texas Eastern capacity replacement services selected by CPG in CPG's 2012 PGC proceeding except for (1) the need for the service, (2) the quantities requested in the RFP as described above, (3) the timing of the RFPs and (4) where No Notice service is sought in a RFP(s), the terms and conditions applicable to such service as described in CPG Statement No. 2.

35. All other provisions of CPG's proposed RFPs as described in CPG Statement No. 2 would be as filed.

36. Neither the acceptance by the Parties of CPG's design day demand pursuant to paragraph 30 of this Settlement nor the Commission's approval of this Settlement shall be deemed to indicate approval of the procedures or methodologies used to derive that design day demand, except to the extent necessary to establish PGC rates in this proceeding.

37. In its PGC compliance filing, CPG will file tariff sheets to modify the direct assignment rules proposed in this proceeding involving bundled sales (Option 2), which will take effect November 1, 2012, as follows:

(a) CPG will provide Choice suppliers with fixed monthly bundled sale quantities ("MBSQ") during each winter month, and the Choice supplier will be

permitted to nominate and purchase gas at CPG city gates throughout each winter month, subject to the maximum daily quantity ("MDQ") limits described in subpart (d) below, up to the MBSQ; and if the full MBSQ is not nominated and purchased by the end of each such winter month, the shortfall ("Bundled Sale Cash-In quantity") will be purchased by the PGC ("Bundled Sale Cash-In" amount) as follows:

(i) The DDR Variation Percentage is the sum of the actual DDRs experienced by a Choice supplier divided by the sum of the pre-month average DDRs that was used to calculate the MBSQ, converted to a percentage. For any month where the DDR Variation Percentage is greater than ninety percent (90%), the Bundled Sale Cash-In amount will equal (1) the product of (a) 0.90 times the lowest absolute low for the Henry Hub index price as published in *platts' Gas Daily* for the applicable month of flow minus (b) the summer index price used for bundled sales (the "Bundled Sale Cash-In index") times (2) the Bundled Sale Cash-In quantity. If the resulting amount is positive, it will be credited to the Choice supplier, or if negative, will be billed to the Choice Supplier.

(ii) In recognition of the effects of extreme warm weather conditions, shortfall amounts will be purchased as follows under such conditions:

A. For any month where (a) the DDR Variation Percentage is less than or equal to ninety percent (90%) and (b) the Bundled Sale Cash-In quantity is less than or equal to the MBSQ minus the product of the DDR Variation Percentage times the MBSQ, then the Bundled Sale Cash-In amount will equal (1) the First of the Month Price called "Texas Eastern Transmission Corp., East Louisiana Zone" as published in *platts'*

Gas Daily Price Guide ("Inside FERC") for the month subsequent to the applicable month in which the cash-in quantity was created, minus the summer index price used for bundled sales (the "Alternative Bundled Sale Cash-In Index") times (2) the Alternate Bundled Sale Cash-In quantity. If the resulting amount is positive, it will be credited to the Choice supplier, or if negative, will be billed to the Choice Supplier.

B. For any month where (a) the DDR Variation Percentage is less than or equal to ninety percent (90%) and (b) the Bundled Sale Cash-In quantity is greater than the MBSQ minus the product of the DDR Variation Percentage times the MBSQ, then the Bundled Sale Cash-In amount will equal (1) the Alternate Bundled Sale Cash-In Index, as defined in Section 37.a.ii, times the DDR Variation Percentage times the MBSQ plus (2) the Bundled Sale Cash-In Index, as defined in Section 37.a.i, times the difference of the Bundled Sale Cash-In quantity minus the product of the DDR Variation Percentage times the MBSQ. If the resulting amount is positive, it will be credited to the Choice supplier, or if negative, will be billed to the Choice Supplier.

(b) Net proceeds related to any Bundled Sale Cash-In activity will be credited/charged to the PGC on a monthly basis.

(c) MBSQs will be based on CPG's storage withdrawal plan, to be updated annually, and communicated as a percentage of each Choice Supplier's pre-month normalized delivery requirements. Example percentages of the pre-month normalized delivery requirements for the 2011-2012 season are shown in Appendix C, Exhibit 1,

Table 2 labeled "Must-Take Monthly Bundled Sale Percentage," and are based on CPG's storage withdrawal plan for 2011-2012.

(d) Bundled sale MDQs will be determined based on the daily delivery flexibility of CPG's storage assets. Example percentages for the maximum daily quantities are shown in Appendix C, Exhibit 1, Table 3 for the 2011-2012 season. The minimum daily quantity is zero. Correspondingly, the percentage of Choice capacity release associated with firm transportation contracts will be modified based on the impact of changing the daily flexibility of the bundled sales quantity as shown in Appendix C, Exhibit 1, Table 1.

(e) Choice suppliers will be required to nominate to CPG a daily quantity for bundled sales no later than 8:45 A.M. Eastern Prevailing Time on each ICE trading day for deliveries applicable to the ICE flow dates. For example, Choice suppliers will be required to nominate quantities on Friday for flow on Saturday, Sunday and Monday. Choice suppliers will not be required to nominate ratable quantities over the flow days. As applicable, nominations must be made on the last ICE trading day prior to any holiday or end of month period as well. If no nomination is received, the nomination quantity will default to zero.

(f) In addition to the bundled sales described above, Choice suppliers will be required to purchase from CPG a separate bundled sale on peak days ("Peaking Sale"). The Peaking Sale will be made on winter days when the Choice supplier's DDR exceeds the sum of the released firm capacity and the MDQ associated with the bundled sale. The Peaking Sale quantity will be the difference between the Choice supplier's DDR minus the sum of the released firm capacity and the MDQ associated with the bundled sale. If

weather conditions cause the Choice supplier's DDR to exceed the Choice supplier's Peak Day Delivery Requirement, the Choice suppliers will be responsible for arranging for supplies to meet the additional delivery requirement for its Choice customers. The Peaking Sale price will be based on the variable cost of CPG's peaking services only since the demand charges associated with CPG's peaking service will already be reflected in the weighted average cost of demand charged for firm transportation capacity releases. Appendix C, Exhibit 1, Table 1 shows Peaking Sale as a percent of the Choice supplier's peak day allocation.

(g) CPG reserves the right to issue operational flow orders ("OFO") that can modify the daily bundled sale flexibility or require certain levels of deliveries from the released firm transportation contracts. These OFOs would be issued for operational reasons only. For example, an OFO could be issued if the aggregate Bundled Sales to Choice Suppliers during the beginning of the month would cause CPG to lose storage deliverability during the end of the same month.

38. The date by which an existing Choice supplier must notify CPG of its direct assignment option election in advance of each winter season shall be changed to July 15.

39. The rate for CPG mandatory firm transportation capacity releases to Choice suppliers beginning November 1, 2012 will be maintained at the level proposed (the weighted average cost of demand for all core market capacity including storage and peaking divided by the percent of firm transportation released when compared to the peak day capacity held for the core market). CPG's proposed rules relating to mandatory assignments to Choice suppliers beginning November 1, 2012 based on the peak day requirements of the choice customers they serve will also be maintained.

40. The settling Supplier Group participants and their affiliates agree not to file any challenge to CPG direct assignment rules before June 1, 2013 and not to propose any changes to CPG's direct assignment rules that would become effective before November 1, 2014.

IV. STANDARDS AND FINDINGS

41. This proceeding involves Commission review pursuant to Sections 1307 and 1318 of the Public Utility Code. Under Section 1307(f), the Commission, after hearing, must determine what portion of the gas costs CPG may recover for a previous 12-month period under the standards set forth in Section 1318. In addition, because CPG has filed tariffs proposing new PGC rates, the Commission must determine whether the requirements of Section 1318 can be met. This determination must precede Commission approval of the Company's proposed rates. The historic period reviewed in this proceeding is the twelve-month reconciliation period ending March 31, 2011. The new tariff rates are intended to become effective December 1, 2011.

A. Historic Reconciliation Period Standards

42. With respect to CPG's gas purchases and gas purchasing practices during the twelve-month historic reconciliation period ending March 31, 2011, all Parties agree, and request the Commission to find, that CPG has met the standards set forth in Section 1318 of the Public Utility Code, as required by Section 1307(f)(5) of the Public Utility Code, as to all historic period purchased gas costs. All Parties request that the Commission find, pursuant to Section 1307(f)(5) of the Public Utility Code, and based upon the evidence presented by the parties in this case, that, during the twelve-month period ended March 31, 2011, CPG has met the requirements of Section 1318 of the Public Utility Code by pursuing a least-cost fuel procurement policy, consistent with its obligation to provide safe, adequate and reliable service

to its customers. Information submitted by CPG in support of the required statutory findings can be found in the following sections of the CPG Exhibit 1:

- A. FERC Participation (§1317(a)(1); §1318(a)(1)): Prefiling, Section 3.
- B. Supplier Negotiations/Renegotiations (§1317(a)(2); §1318(a)(2)): Prefiling, Sections 2 and 5.
- C. Efforts to Obtain Lower Cost Supplies (§1317(a)(3); §1318(a)(3)): Prefiling, Sections 1, 2, and 5.
- D. Withheld Supplies (§1317(a)(4); §1318(a)(4)): Prefiling, Section 5.
- E. Non-Affiliated Purchases (§1317(b); §1318(b)): Prefiling, Section 13.
- F. Least Cost Fuel Procurement Policy (§1317(a); §1318(a)): Prefiling, Section 1, 2 and 5.
- G. Calculation of 2011 PGC Rates:
 - 1. June 1, 2011 Filing, Attachments (1) - (4).
 - 2. June 1, 2011 Filing, "E" Factor Calculations: Filing, Attachment (4).
 - 3. June 1, 2011 Filing, Written Direct Testimony of William J. McAllister.
- H. Reliability (§1317(c)): Prefiling, Section 14.

B. Projected Period Findings

43. With respect to the twelve-month period beginning December 1, 2011, the period of time during which the proposed rates contained in this Settlement would be in effect, all Parties agree and request the Commission to find that CPG has satisfied each of the standards for a least cost procurement policy set forth in Section 1318 of the Public Utility Code, including the standards set forth in Sections 1318(a)(1), 1318(a)(2), 1318(a)(3), 1318(a)(4), 1318(b)(1), 1318(b)(2) and 1318(b)(3), based upon the evidence of record in this proceeding. Nevertheless, it is expressly understood and agreed that such findings, relating to the rates to become effective December 1, 2011, are made solely for the purpose of setting prospective rates and shall be

subject to further review in an appropriate future proceeding. This Section of the Settlement, Section IV.B., is not intended to limit or prevent any party from challenging projected gas purchases that actually have been made, including those made during the interim period of April 1, 2011 through November 30, 2011, and future gas purchasing practices that have been implemented, or from reviewing whether these gas purchases and gas purchasing practices have, in fact, complied with the standards of Section 1318, except as provided in Section III above.

44. If, in an appropriate future proceeding, gas purchases and gas purchasing practices relating to the period December 1, 2011, through November 30, 2012 are challenged, the Commission's findings made pursuant to Section IV.B. of this Settlement shall pose no bar to the examination of such purchases and practices including, but not limited to, disallowance of or reductions to, such costs during the one-year period commencing December 1, 2011, except as provided in Section III above.

45. The Parties also agree that future examination of the gas costs relating to the period April 1, 2010 through November 30, 2011 to determine whether CPG's experienced and projected gas purchases and gas purchasing practices complied with the standards set forth in Section 1318 of the Public Utility Code, 66 Pa. C.S. § 1318, shall be permitted and that the Commission's adoption of the findings under Section IV.B. of this Settlement shall not be construed to limit or prevent any disallowance or reduction of such costs, except as provided in Section III above.

V. CONDITIONS OF SETTLEMENT

46. This Settlement is conditioned upon the Commission's approval of the terms and conditions contained herein without modification, addition or deletion. If the Commission modifies the Settlement or fails to approve, by December 1, 2011, the terms and conditions of

this Settlement and the rates contained in Appendix A, as modified to reflect updates and tariff modifications traditionally performed on December 1 effective for service rendered on and after December 1, 2011, then any of the Parties may elect to withdraw from this Settlement and may proceed with litigation. 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 Parties within five (5) business days after the entry of an order modifying or disapproving the Settlement.

47. If the Commission modifies or does not approve the Settlement and the proceedings continue to hearings on the issues that are the subjects of this Settlement, the Parties reserve their respective rights to present additional testimony and to conduct full cross-examination, briefing and argument on these subjects.

48. Except as otherwise specifically provided in this document, this Settlement is proposed by the Parties to settle all issues in the instant proceeding and is made without any admission against, or prejudice to, any position that any Party may adopt during any subsequent litigation of this proceeding if the Commission disapproves or modifies this Settlement or any position that any Party may adopt in any other proceeding.

49. It is understood and agreed among the Parties that this Settlement is the result of compromises by all Parties and does not necessarily represent the position(s) that would be advanced by any party in the event this proceeding were to be litigated fully.

50. This Settlement is being presented only in the context of this Section 1307(f) proceeding in an effort to resolve certain outstanding issues in a manner that is fair and reasonable. Except as otherwise specifically provided in this document, this Settlement reflects compromises on all sides, and is presented without prejudice to any position that any of the

parties may have advanced and without prejudice to the positions that any of the parties may advance in the future on the merits of the issues.

51. The Parties acknowledge and agree that this Settlement shall have the same force and effect as if the Parties had fully litigated this proceeding with regard to the historic period ended March 31, 2011.

52. Except as provided above, all Parties agree to fully support the terms and conditions of the Settlement during further litigation in this proceeding.

53. This Settlement may be executed in counterparts.

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


1. That Administrative Law Judge Kandace F. Melillo and the Commission approve this Settlement, including all terms and conditions thereof.

2. That the Commission enter a final Order consistent with this Settlement that: (a) finds that there is sufficient evidence in the record for this Commission to make the findings referenced in Sections IV.A and IV.B of this Settlement; and (b) sets forth the findings referenced in Section IV.A and IV.B of this Settlement.

3. That the Commission enter a final Order, consistent with this Settlement: (a) approving the proposed rates contained in Appendix A hereto, as modified to reflect updates and tariff modifications traditionally performed as part of CPG's December 1 PGC compliance filings, and (b) directing CPG to file a final tariff implementing such rates for gas service rendered by CPG on and after December 1, 2011.

4. That the Commission terminate and mark closed its inquiry and investigation at Docket Nos. R-2011-2238949, C-2011-2243177 and C-2011-2248231.

Respectfully submitted,



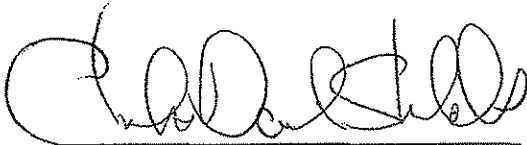
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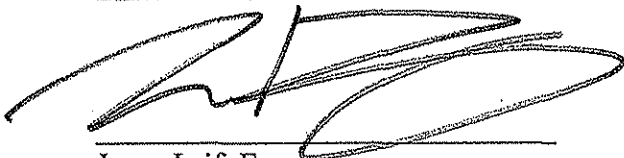
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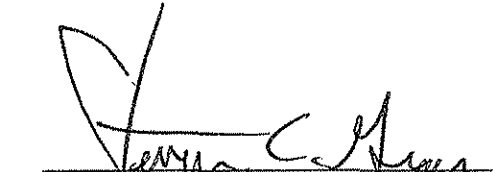


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Counsel for the Supplier Group

Dated: August 23, 2011



Steven C. Gray
Office of Small Business Advocate
Suite 1102, Commerce Building
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Harrisburg, PA 17101

Counsel for the Office of Small Business
Advocate

APPENDIX A
(CPG Settlement Rates – Subject to Updates)

Schedule A
Settlement

UGI Central Penn Gas, Inc.
Computation of the Cost of Gas
Applicable to Rates: R, G, RS & O.

Effective December 1, 2011
Computation Year Ending November 30, 2012

C - Projected Cost	\$	48,488,437
S - Projected Sales - Dth		7,961,494
C / S Projected Cost per Dth	\$	6.0900
E - Experienced Cost Rates G,RS,O	\$	(1,344,334)
E - Experienced Cost Rate R	\$	(1,436,378)
E / S Experienced Cost per Dth Rates G,RS,O*	\$	0.1445
E / S Experienced Cost per Dth Rate R* (or Gas Cost Adjustment (GCA))	\$	0.1793
PGC = (GSC + GCA) @ 12.1.2011 - Proposed Rates G,RS,O (per Dth)	\$	6.2345
PGC = (GSC + GCA) @ 12.1.2011 - Proposed Rate R (per Dth)	\$	6.2693
PGC = (GSC + GCA) @ 12.1.2011 - Proposed Rates G,RS,O (per Mcf)**	\$	6.4153
PGC = (GSC + GCA) @ 12.1.2011 - Proposed Rate R (per Mcf)**	\$	6.4511
PGC = (GSC + GCA) @ 6.1.2011 - Current Rate G,RS,O (per Dth)	\$	6.2356
PGC = (GSC + GCA) @ 6.1.2011 - Current Rate R (per Dth)	\$	6.2704
PGC Change Rate G,RS,O (per Dth)	\$	(0.0011)
PGC Change Rate R (per Dth)	\$	(0.0011)
Residential Heating Percent Reduction		-0.01%

* Reflects additional migration rider applicable volumes of 50,000 Dth. See Schedule C, Page 1.

**UGI Central Penn Gas, Inc.
Computation of the Experienced Cost Factor: E
For the 2011 PGC Year**

Effective December 1, 2011
Computation Year Ending November 30, 2012

REFUND CREDITS

Prior	(Amortized Balance as of November 30, 2011)	Schedule C, Page 2	\$	33,096
Current Rate R,G,RS,O	(Twelve Months Ended November 30, 2011)	Schedule C, Page 3	\$	8,999
Interest Rate R,G,RS,O	(Twelve Months Ended November 30, 2011)	Schedule C, Page 3	\$	664

OVER / (UNDER) COLLECTION

Prior	(Amortized Balance as of November 30, 2011)	Schedule C, Page 4		(1,967,577)
Current	(Twelve Months Ended November 30, 2011)	Schedule C, Page 6		347,178
Interest	(Twelve Months Ended November 30, 2011)	Schedule C, Page 6		141,262

TOTAL E \$ (1,436,378)

TOTAL S (Dth) 7,961,494
SETTLEMENT Adjustment for Choice Sales Volumes 50,000
SETTLEMENT Sales Volumes 8,011,494

E/S Refund/(Collection) \$/Dth: Rate R \$ (0.1793)

Tennessee PCB Refund - Rates G, RS, O

Prior (Rates G,RS,O)	(Twelve Months Ended November 30, 2011)	Schedule C, Page 2A	\$	(18,408)
Current (Rates G,RS,O)	(Twelve Months Ended November 30, 2011)	Schedule C, Page 3	\$	85,470
Interest (Rates G,RS,O)	(Twelve Months Ended November 30, 2011)	Schedule C, Page 3	\$	6,574

TOTAL E - Tennessee PCB Refund \$ 73,637

TOTAL S - Rates G, RS ,O (Dth) 2,645,877

E/S Tennessee PCB Refund - Rates G,RS,O \$/Dth: \$ 0.0348

Total E/S Refund/(Collection) for Rates G,RS,O \$ (0.1445)

Note: The Total E/S Refund/(Collection) for Rates G, RS, O includes the sum of the E/S Refund/(Collection) for Rate R applicable to all customers and the E/S Tennessee PCB Refund - Rates G, RS, O applicable only to Rates G, RS, O.

APPENDIX B
(CPG design cold temperatures)

UGI Central Penn Gas, Inc.

Location	Book 1 Attachment 14-2 Pages 1-3 Design	30-year 1975-2004			30-year 1980-2009			
		Normal	Design	%	Normal	Design	%	
CPG	Southern	6,577	4,603	5,136	11.6%	4,543	5,067	11.3%
	Central	5,939	5,088	5,627	11.1%	5,027	5,565	10.7%
	Northern	7,147	5,882	6,568	12.2%	5,812	6,449	11.0%

The Normal and Design heating degree day totals for the 30-Year range, 1980 to 2009, are derived by ranking daily temperatures for each calendar year from lowest to highest.

An average and standard deviation are calculated for the 30 coldest days.

An average and standard deviation are calculated for the 30 2nd coldest days from each calendar year.

This process is repeated 151 times.

The averages for each day, 1 through 151, are then subtracted from 65 to get the heating degree day equivalent.

This provides total heating degree days for the normal winter.

The Design Winter heating degree days are derived by taking the standard deviation multiplied by a 95% confidence interval which is 1.645.

The corresponding standard deviation times 1.645 is then subtracted from each 30 year average for days 1 through 151.

This provides the "statistical" design day, which is then subtracted from 65 to get the heating degree day equivalent.

This provides total heating degree days for the design winter.

Please note that the Day 1 design cold temperature/heating degree days are replaced with the temperatures agreed upon from CPG's 2009 PUC settlement.

UGI Central Penn Gas, Inc.

Day	CPG South		CPG Central		CPG North	
	Temp F	HDD	Temp F	HDD	Temp F	HDD
1	-3.5	69	-5.0	71	-14.0	79
2	4.2	61	-1.7	67	-9.3	75
3	8.9	58	1.6	63	-6.4	71
4	8.9	56	2.3	62	-3.3	69
5	10.4	55	4.8	60	-1.5	67
6	11.3	54	5.6	60	-0.7	66
7	12.3	53	6.5	58	0.3	65
8	12.9	52	7.7	57	1.3	64
9	13.5	52	8.4	57	1.8	63
10	14.2	51	9.2	56	2.6	62
11	14.9	50	10.2	56	3.5	61
12	15.3	50	10.7	54	4.1	61
13	15.8	49	11.2	54	4.8	60
14	16.5	49	11.7	53	5.4	60
15	16.9	48	12.4	53	6.0	59
16	17.7	47	13.1	52	6.6	58
17	18.1	47	13.5	51	7.1	58
18	18.5	46	14.1	51	7.7	57
19	19.0	46	14.4	51	8.1	57
20	19.5	46	14.9	50	8.8	57
21	19.9	45	15.3	50	8.9	56
22	20.2	45	15.9	49	9.3	56
23	20.7	44	15.3	49	9.6	56
24	21.0	44	16.3	48	9.9	55
25	21.4	44	17.2	48	10.3	55
26	21.8	43	17.5	47	10.6	54
27	22.0	43	17.9	47	11.1	54
28	22.2	43	18.2	47	11.5	53
29	22.5	42	18.6	46	12.0	53
30	22.9	42	19.2	46	12.5	53
31	23.3	42	19.4	46	12.8	52
32	23.7	41	19.4	46	13.0	52
33	24.0	41	19.8	45	13.4	52
34	24.2	41	20.2	45	13.7	51
35	24.4	41	20.3	46	14.0	51
36	24.8	40	20.6	44	14.2	51
37	24.9	40	20.8	44	14.5	51
38	25.2	40	21.5	44	14.8	50
39	25.5	39	21.5	43	15.1	60
40	25.8	39	21.9	43	15.3	50
41	26.1	39	21.9	43	15.7	49
42	26.3	38	22.4	43	15.9	49
43	26.6	38	22.7	42	16.1	48
44	26.9	38	22.9	42	16.4	49
45	27.1	38	23.1	42	16.8	48
46	27.3	38	23.5	42	17.0	48
47	27.6	37	23.8	41	17.2	48
48	27.8	37	23.7	41	17.6	47
49	27.9	37	23.6	41	18.0	47
50	28.2	37	24.3	41	18.2	47
51	28.3	37	24.5	40	18.4	47
52	28.6	36	24.9	40	16.6	46
53	28.7	36	25.4	40	16.9	46
54	29.1	36	25.4	40	19.0	46
55	29.2	36	25.5	39	19.7	45
56	29.4	36	25.8	39	19.8	45
57	29.5	35	26.2	39	20.2	45
58	29.7	35	26.5	39	20.3	46
59	29.8	35	26.8	38	20.5	44
60	30.1	35	27.0	38	20.6	44
61	30.3	35	27.4	38	21.0	44
62	30.5	35	27.6	37	21.3	44

UGI Central Penn Gas, Inc.

Day	CPG South		CPG Central		CPG North	
	Temp.F	HDD	Temp.F	HDD	Temp.F	HDD
63	30.7	34	27.8	37	21.5	44
64	30.8	34	27.9	37	21.7	43
65	31.2	34	28.1	37	22.0	43
66	31.4	34	28.1	37	22.4	43
67	31.5	33	28.6	36	22.5	42
68	31.6	33	28.7	36	22.8	42
69	32.0	33	28.8	36	23.1	42
70	32.1	33	29.3	36	23.4	42
71	32.3	33	29.5	36	23.6	41
72	32.5	32	29.7	35	23.8	41
73	32.7	32	29.8	35	23.9	41
74	32.8	32	30.0	35	24.1	41
75	32.9	32	30.2	35	24.2	41
76	33.0	32	30.4	35	24.7	40
77	33.1	32	30.5	34	24.9	40
78	33.2	32	30.5	34	25.0	40
79	33.4	32	30.7	34	25.3	40
80	33.5	32	30.8	34	25.3	40
81	33.6	31	30.9	34	25.5	39
82	33.8	31	31.2	34	25.7	39
83	34.0	31	31.5	34	25.8	39
84	34.3	31	31.8	33	26.0	39
85	34.5	31	32.1	33	26.2	39
86	34.6	30	32.1	33	26.3	39
87	34.8	30	32.1	33	26.5	38
88	35.1	30	32.4	33	26.7	38
89	35.2	30	32.9	32	26.9	38
90	35.4	30	33.2	32	27.1	38
91	35.6	29	33.2	32	27.2	38
92	35.7	29	33.3	32	27.4	38
93	35.9	29	33.4	32	27.7	37
94	36.0	29	33.5	32	27.8	37
95	36.3	29	33.6	31	28.1	37
96	36.4	29	33.9	31	28.2	37
97	36.6	28	34.0	31	28.4	37
98	36.7	28	34.1	31	28.6	36
99	36.9	28	34.4	31	28.9	36
100	37.0	28	34.4	31	29.0	35
101	37.3	28	34.5	30	29.1	35
102	37.4	28	34.7	30	29.4	35
103	37.5	27	34.9	30	29.5	35
104	37.7	27	35.1	30	29.7	35
105	37.9	27	35.2	30	29.8	35
106	38.0	27	35.3	30	30.1	35
107	38.3	27	35.5	29	30.2	35
108	38.4	27	35.7	29	30.5	35
109	38.5	26	35.7	29	30.6	34
110	38.7	26	36.0	29	30.8	34
111	38.9	25	36.2	29	31.0	34
112	39.1	25	36.4	29	31.0	34
113	39.3	25	36.7	28	31.2	34
114	39.5	25	36.7	28	31.3	34
115	39.8	25	37.1	28	31.6	33
116	39.9	25	37.2	28	31.8	33
117	40.1	25	37.3	28	31.8	33
118	40.3	25	37.3	28	32.1	33
119	40.4	25	37.6	27	32.2	33
120	40.6	24	37.8	27	32.4	33
121	40.8	24	38.1	27	32.7	32
122	41.0	24	38.0	27	32.7	32
123	41.2	24	38.2	27	33.0	32
124	41.4	24	38.4	27	33.1	32

UGI Central Penn Gas, Inc.

Day	CPG South		CPG Central		CPG North	
	Temp F	HDD	Temp F	HDD	Temp F	HDD
125	41.6	23	38.6	26	33.3	32
126	41.7	23	38.7	26	33.6	31
127	41.9	23	38.8	26	33.8	31
128	42.0	23	39.0	26	34.1	31
129	42.2	23	39.1	26	34.3	31
130	42.3	23	39.3	26	34.5	31
131	42.5	23	39.5	26	34.5	30
132	42.7	22	39.5	25	34.6	30
133	42.9	22	39.7	25	35.0	30
134	43.1	22	40.0	25	35.2	30
135	43.2	22	40.2	25	35.4	30
135	43.3	22	40.4	25	35.5	30
137	43.5	21	40.5	25	35.6	29
138	43.7	21	40.7	24	35.8	29
139	43.8	21	40.9	24	35.9	29
140	43.9	21	41.0	24	35.1	29
141	44.1	21	41.1	24	36.3	29
142	44.3	21	41.6	23	36.4	29
143	44.4	21	41.7	23	36.6	28
144	44.5	20	41.7	23	36.8	28
145	44.7	20	41.8	23	36.8	28
146	44.8	20	41.8	23	37.1	28
147	45.0	20	42.0	23	37.2	28
148	45.1	20	42.1	23	37.3	28
149	45.3	20	42.4	23	37.4	28
150	45.5	19	42.7	22	37.6	27
151	45.7	19	42.6	22	37.7	27

APPENDIX C
(Direct Assignment Information)

Table 1

	Peak Day Allocation		
	FT Release ¹	Bundled Sale ¹	Peaking Sale ¹
UGI	52%	28%	20%
PNG	35%	56%	9%
CPG	59%	36%	5%

Table 2

	Must-Take Monthly Bundled Sale Percentage ²				
	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
UGI	5%	22%	38%	42%	44%
PNG	26%	68%	54%	77%	78%
CPG	18%	33%	55%	52%	44%

Table 3

	Max Daily Bundled Sale Quantity Percentage ³					
	Nov-11	Dec-11	Jan-12	Feb 1-15, 2012	Feb 16-29, 2012	Mar-12
UGI	15%	100%	100%	100%	75%	65%
PNG	25%	100%	100%	100%	80%	65%
CPG	25%	100%	100%	100%	70%	50%

1. FT Release Quantity = Peak day DDR x FT Release percentage in Table 1
 Maximum Daily Bundled Sale Quantity = Peak day DDR x Bundled Sale percentage in Table 1
 Maximum Daily Peaking Sale Quantity = Peak day DDR x Peaking Sale percentage in Table 1
2. Must-Take Monthly Bundled Sale Quantity = Pre-month average DDR x Number of days in month x Percentage in Table 2
3. For each month, the Maximum Daily Bundled Sale Quantity defined in Table 1 is adjusted by multiplying the percentages in Table 3

Peak Day Allocation

Example based on all Choice Participation as of April 2011

Peak Day Delivery Requirement (Dth)		Table 1		
		Peak Day Allocation		
		FT Release	Bundled Sale	Peaking Sale
UGI	89,002	52%	28%	20%
PNG	21,606	35%	56%	9%
CPG	7,999	59%	36%	5%

Peak Day Allocation (Dth)				
	FT Release	Bundled Sale	Peaking Sale	Total
UGI	46,281	24,921	17,800	89,002
PNG	7,562	12,099	1,945	21,606
CPG	4,719	2,880	400	7,999

Must-Take Monthly Bundled Sale Quantity

Example based on all Choice Participation as of April 2011

Pre-month Average DDR (Dth)					
	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
UGI	852,610	1,248,134	1,579,340	1,234,434	1,077,080
PNG	175,078	303,822	427,321	325,322	275,781
CPG	51,609	85,541	94,281	96,769	92,225

Table 2

Must-Take Monthly Bundled Sale Percentage					
	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
UGI	5%	22%	38%	42%	44%
PNG	26%	68%	54%	77%	78%
CPG	18%	33%	55%	52%	44%

Must-Take Monthly Bundled Sale Quantity (Dth)					
	Nov-11	Dec-11	Jan-12	Feb-12	Mar-12
UGI	45,800	275,595	596,968	512,296	471,080
PNG	46,015	207,920	231,468	249,847	215,065
CPG	9,362	28,133	51,860	50,355	40,362

Daily Bundled Sale Flexibility

Example based on all Choice Participation as of April 2011

Table 1

Peak Day (Dth)		Peak Day Allocation		
		Release	Bundled Sale	Peaking Sale
UGI	89,002	83%	28%	70,022
PNG	21,606	85%	56%	18,365
CPG	7,999	59%	36%	4,719

Table 3

	Max Daily Bundled Sale Quantity Percentage					
	Nov-11	Dec-11	Jan-12	Feb 1-15, 2012	Feb 16-29, 2012	Mar-12
UGI	15%	100%	100%	100%	75%	65%
PNG	25%	100%	100%	100%	80%	65%
CPG	25%	100%	100%	100%	70%	50%

	Maximum Daily Bundled Sale Quantity (Dth)					
	Nov-11	Dec-11	Jan-12	Feb 1-15, 2012	Feb 16-29, 2012	Mar-12
UGI	3,738	24,921	24,921	24,921	18,690	16,198
PNG	3,025	12,099	12,099	12,099	9,679	7,865
CPG	720	2,880	2,880	2,880	2,016	1,440

APPENDIX D
(CPG Statement in Support)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY	:	
COMMISSION, ET AL.	:	
	:	Docket Nos. R-2011-2238949
v.	:	C-2011-2243177
	:	C-2011-2248231
UGI CENTRAL PENN GAS, INC.	:	

**UGI CENTRAL PENN GAS, INC. STATEMENT
IN SUPPORT OF STIPULATION IN SETTLEMENT OF
SECTION 1307(f) RATE INVESTIGATION**

TO ADMINISTRATIVE LAW JUDGE KANDACE F. MELILLO:

I. INTRODUCTION

UGI Central Penn Gas, Inc. (“CPG” or the “Company”) hereby submits this Statement in Support of the Stipulation in Settlement of Section 1307(f) Rate Investigation (“Settlement”) entered into by CPG, the Bureau of Investigation and Enforcement (“BI&E” or, prior to August 11, 2011, the Bureau of Investigation and Enforcement (“BI&E”) BI&E of the Pennsylvania Public Utility Commission (“Commission”), the Office of Consumer Advocate (“OCA”), the Office of Small Business Advocate (“OSBA”), and CenterPoint Energy Services, Inc. (“CenterPoint”), Jerome H. Rhoads, Inc. d/b/a Rhoads Energy Corporation (“Rhoads”) and Shipley Energy Company with Shipley Choice LLC (collectively, “Shipley” and in combination with CenterPoint and Rhoads collectively the “Supplier Group”).¹ The Settlement has been entered into or not opposed by all parties and resolves all issues in this proceeding.

¹ In addition, the CPG Large Users Group (“CPGLUG”), the only other party in this proceeding, has indicated that it does not oppose the Settlement.

CPG believes that this Settlement is in the best interests of CPG, its customers and the Joint Petitioners, and therefore is in the public interest and should be approved.

The Settlement of this proceeding was achieved only after a comprehensive investigation of CPG's gas procurement practices. CPG responded to approximately 188 formal discovery requests, many of which had multiple subparts. Parties also filed multiple rounds of testimony, including CPG's direct; BI&E, OCA, and Supplier Group direct testimony; CPG, OCA, BI&E, OSBA and Supplier Group rebuttal testimony; and CPG and Supplier Group surrebuttal testimony. In addition, the Joint Petitioners participated in numerous settlement discussions which ultimately led to the Settlement.

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

II. SETTLEMENT TERMS

A. Migration Rider

The development of the E-Factor component of CPG's projected PGC rates is shown on Schedule C, page 1, of CPG's June 1, 2011 Book 2 filing. As that schedule shows, the E-Factor unit rate was determined by dividing total undercollections and interest by projected sales for the twelve-month period ending November 30, 2012. See also CPG Statement No. 1, pp. 5-6.

On pages 3-5 of BI&E Statement No. 1, BI&E witness Debra Backer argued that for the purpose of calculating the E-factor for the twelve month period ending November 30, 2012, total projected sales should include total projected Choice volumes of 700,000 Dth since Choice customers pay or receive a migration rider during the first year after they migrate from PGC service.

In his rebuttal testimony, CPG witness William J. McAllister agreed that customer Choice volumes subject to the migration rider should be included in projected sales when computing the E-Factor rate, but noted that not all current Choice customers are still subject to the migration rider since they have been on transportation service for periods longer than one year. He also estimated that the volumes of Choice customers subject to the migration rider would be 50,000 Dth for twelve-month period ending November 30, 2012. CPG Statement No. 1-R, pp. 2-3.

The Settlement fairly resolves this issue by providing that CPG will use its 50,000 Dth projection of Choice volumes potentially subject to the migration rider in developing its E-Factor in its compliance filing in this proceeding, and will also continue to consider customer Choice volumes subject to the migration rider in developing the E-Factor in future PGC filings (par. 27-28).

B. Design Cold Temperatures Other Than Peak Day

On pages 4 through 7 of his direct testimony, Mr. Mierzwa reviewed how CPG calculated the non-peak day winter season requirements of its core market customers, concluded that this methodology resulted in planning for a winter about twenty-five percent (25%) colder than normal, reviewed the thirty-year average and coldest winters in the four locations used to compute the seasonal requirements for CPG's service territory, and concluded that CPG should only plan for winter seasons about ten percent colder than normal.

In his rebuttal testimony, Mr. Beasten argued that CPG's method of calculating seasonal requirements was consistent with the methodology adopted in CPG's 2009 PGC proceeding to compute the peak day requirements of CPG's service territory, and noted

the potential costs and reliability risks if CPG did not have sufficient gas supply assets in place to meet seasonal requirements. CPG Statement No. 2-R, pp. 2-3.

Under paragraphs 29 and 30 of the Settlement, CPG has agreed to utilize the design temperature profile shown in Appendix B to the Settlement for the 2011-2012 winter season, and in calculating the design day requirements for days other than the coldest day in future PGCs, to perform a statistical analysis for each day using weather data for a thirty year period, updated every five years utilizing the statistical methodology show on page one of Appendix B. As shown on page one of Appendix B, this methodology would result in planning for a winter season about eleven percent (11%) colder than normal. This is fair resolution of this issue that strikes an appropriate balance between security and least cost.

C. RFP Revisions

On pages 11-20 of his direct testimony, Mr. Beasten described a requests for proposals (“RFP”) CPG plans to issue for (1) an eight-to-ten day 9,221 Dth/day peaking service for the northern portion of its service territory and (2) to evaluate potential replacements for a release of Texas Eastern capacity from UGI Utilities, Inc. – Gas Division that set to expire October 31, 2012. Amongst other things, Mr. Beasten noted that the RFP to replace the Texas Eastern capacity release would be issued in the summer of 2011 (CPG Statement No. 2, p. 19, line 9), would seek a five year term (CPG Statement No. 2, p. 19, line 19), and would request a service that would have to provide CPG with the right to call on the service on an intra-day basis (“no notice service”). Bidders in each of the RFP’s would have three weeks to respond (CPG Statement No. 2, p. 19, lines 9-10).

In his direct testimony, Mr. Mierzwa argued that the quantities of service requested in the RFPs should be adjusted to reflect his proposed seasonal requirements adjustments, and that the RFP to explore replacements for the Texas Eastern capacity release should (1) not request no notice service since the released capacity being replaced did not provide such service, and (2) afford potential bidder six months to respond. OCA Statement No. 1, pp. 8-9.

In his rebuttal testimony Mr. Beasten noted, apart from his concerns about Mr. Mierzwa's peak day and seasonal requirements recommendations, that extending the Texas Eastern RFP response time to six months was unnecessary because potential bidders were already well aware of CPG's expiring contracts, and are unlikely to respond until shortly before the end of the RFP period no matter how long or short that period is (CPG Statement No. 2-R, p. 3-4).

To reflect the updated design cold temperatures agreed to in the Settlement, CPG has agreed to revise its peaking service RFP to request an eleven-day, as opposed to a nine-day, service at a 100% load factor. The daily quantity requested in the peaking service RFP would remain at 9,221 Dth/day for the winter of 2011-2012, and potential bidders would have four, as opposed to three, weeks to respond to the RFP.

With respect to the Texas Eastern capacity release replacement RFP, potential bidders would also have four weeks to respond. If CPG proposes to replace this capacity with a no notice service, it will be required to demonstrate through the RFP process that the no notice service is the lowest cost option, including reasonably expected off-system margins and capacity release revenues that would result from the availability of the no notice service. To do this CPG would, at a minimum, conduct RFPs for two services.

One RFP would be for a no-notice service as described in CPG Statement No. 2, but the RFP would be revised from a ten-day to a five-day service at a 100 percent load factor. The second RFP would be for a 15-day day-ahead peaking service at a 100 percent load factor that would be nominated during the normal Intercontinental Exchange ("ICE") trading period (for example, CPG would nominate the service on Friday morning between 9:00 AM and 9:30 AM for ratable delivery over the period Saturday, Sunday and Monday). The maximum daily quantity for the Texas Eastern replacement services (whether the replacement services or some portion thereof are no notice services) will be 5,700 Dth for a five-year term beginning with the 2012-2013 winter season. All Parties would have the right to challenge the Texas Eastern capacity replacement services selected by CPG in CPG's 2012 PGC proceeding except for (1) the need for the service, (2) the quantities requested in the RFP as described in the Settlement, (3) the timing of the RFPs and (4) where no notice service is sought in a RFP(s), the terms and conditions applicable to such service as described in CPG Statement No. 2.

Under the Settlement, the RFP processes will otherwise be conducted as proposed by CPG (par. 33).

These Settlement revisions fairly resolve the disputes over CPG's proposed RFPs and should be approved.

D. Supplier Group Issues

Consistent with the terms of CPG's 2010 PGC settlement, CPG proposed new mandatory direct assignment rules for Choice suppliers in this proceeding for the annual period beginning November 1, 2012. See CPG Statement No. 3, pp. 5-12; June 7, 2011 supplemental *pro forma* tariff pages.

In his direct testimony Supplier Group witness James L. Crist recommended, with respect to these proposed future direct assignment rules, that (1) capacity assigned by CPG to Choice suppliers should include all interstate pipeline and storage capacity, (2) the price charged for such assigned capacity should be at the contract rate for the capacity, and not the weighted average costs of PGC capacity, (3) the amount of capacity assigned should be based on the amount of capacity used by the Choice customers served by the Choice supplier during an average day during the coldest month as opposed to the peak day requirements of such Choice customers, (4) assignments to Choice suppliers should be voluntary, and (5) Choice customers should receive a share of the seventy-five percent (75%) of off-system sales revenues currently flowed back to PGC customers. Supplier Group Statement No. 1, p. 5-6. Mr. Crist also compared CPG's Choice program to those of Columbia Gas, Equitable Gas, National Fuel Gas and PECO and found those programs to have "superior" capacity assignment rules. Supplier Group Statement No. 1, pp. 28-31.

In his rebuttal testimony CPG witness Shaun M. Hart noted, amongst other things, that: (1) CPG cannot release peaking contracts and under FERC rules cannot release certain so-called section 7(c) contracts, including storage contracts (CPG Statement No. 3-R, pp. 8-12), (2) CPG could not fulfill its statutory supplier-of-last-resort ("SOLR") obligations if it released storage contracts to Choice suppliers since there are no statutory or regulatory mechanisms or contract terms that could ensure that storage inventories would be present in the event CPG had to re-call the storage contracts to perform its SOLR obligations, nor could CPG be assured of being able to find replacement supplies on design cold days in its market area (CPG Statement No. 3-R, pp 12-16), (3) Mr.

Crist's proposals to release capacity at contract rates (CPG Statement No. 3-R, pp. 23-25), make releases voluntary (CPG Statement No. 3-R, pp. 28-29), or to release capacity on average monthly, rather than peak day, basis (CPG Statement 3-R, pp. 26-28) would result in impermissible cost shifting and be unfair to PGC customers (see 66 Pa.C.S. § 2203(4)), and (4) that the sharing of off-system revenues would be unnecessary because Choice suppliers will be able to maximize the value of capacity released to them in secondary markets and retain 100% of proceeds of such activities (CPG Statement No. 3-R, pp. 30-31). Mr. Hart also showed that the capacity release provisions of other NGDCs in the eastern part of Pennsylvania deemed superior by Mr. Crist also do not provide for the release storage capacity to Choice supplier, and instead the NGDCs retain storage assets and use them to provide balancing services, the costs of which are recovered from tariff charges (CPG Statement No. 3-R, pp. 16-21).

In their rebuttal testimonies Mr. Mierzwa, BI&E witness Michael J. Gruber and OSBA witness Robert D. Knecht also raised concerns about some or all Mr. Crist's proposals. Notably, however, Mr. Mierzwa expressed some support for sharing some portion of the seventy-five percent (75%) of off-system sales margins with Choice suppliers if they were not provided access to storage or peaking assets (OCA Statement No. 1-R, p. 7), as did Mr. Knecht (OSBA Statement No. 1, p. 9-10).

Under the Choice supplier capacity release rules proposed by CPG in this proceeding, beginning November 1, 2012, Choice suppliers could elect to either receive a release of firm transportation ("FT") capacity equal to the peak day requirements of their Choice customers ("Option One"), or elect to receive a lesser assignment of "FT" capacity and receive bundled city gate sales on daily basis to cover the difference

between their FT supplies and the Daily Delivery Requirements of their Choice customers at summer index prices (“Option Two”). Under Option Two, Choice suppliers would thus receive the seasonal benefits of acquiring winter supplies at summer prices, while preserving the ability of CPG to retain storage and peaking assets to meet its SOLR obligations in a reliable manner given market conditions in the eastern part of the Commonwealth.

Under the Settlement, beginning November 1, 2012, CPG’s Option Two rules will be modified to provide additional flexibility to Choice suppliers while still preserving the ability of CPG to meet its SOLR obligations. Specifically, Choice suppliers will be provided with a bundled sale quantity on a monthly basis, based on the projected usage of their Choice customers under normal weather conditions, and will have the additional flexibility of deciding when they want to receive these bundled sales quantities throughout the month. In the event colder than normal weather, CPG will make additional bundled city gate sales at summer index prices. Bundled sales quantities not taken during a month would be purchased by the PGC at an index price that would encourage Choice suppliers to take delivery of all their bundled city gate quantities during a month, and thus permit CPG to adhere to its storage inventory drawdown schedule, or at a secondary index price for the portion of reduced city gate purchases related to the weather if significantly warmer weather than normal prevails. CPG has also agreed to move the date by which Choice Suppliers have to make their election between Option One and Option Two to July 15. The net effect of these Settlement provisions is to provide Choice suppliers with even more flexibility, while preserving the

ability of CPG to (1) meet its SOLR obligations, (2) avoid cost shifting and (3) handle its inability to release certain peaking services and section 7(c) contracts.

The settling Supplier Group participants and their affiliates have also agreed under the Settlement to not file any challenge to CPG direct assignment rules before June 1, 2013, and to not propose in any changes to the CPG Companies' direct assignment rules that would become effective before November 1, 2014

These Settlement terms provide for a fair resolution of the concerns of the Supplier Group while preserving reliability and avoiding cost shifting, and should be adopted.

III. CONCLUSION

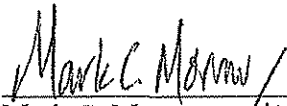
As explained above, the Settlement is in the public interest and should be approved. The Settlement was achieved only after considerable investigation of CPG's gas procurement practices, through both discovery and submission of testimony by a number of Joint Petitioners in this proceeding. The Settlement, if approved by Administrative Law Judge Kandace F. Melillo and the Commission, will reduce the amount of expense and effort that will be required by the Joint Petitioners and the Commission to bring this matter to a conclusion. Furthermore, the Joint Petitioners and the Commission will be able to avoid the substantial effort and expense that would be incurred in continuing to litigate this proceeding, including preparation for and participation in hearings, preparation of briefs, reply briefs, exceptions, and replies to exceptions.

All of the Joint Petitioners to the Settlement also request that the required statutory findings be made in this proceeding. These statutory findings are appropriate

and are amply supported by the information outlined in the Settlement and in the testimony filed by CPG in this proceeding.

The Settlement is the result of compromise. Each of the agreements set forth in the Settlement resolves a dispute fairly and without the expense and uncertainty associated with litigation. CPG accordingly fully supports the Settlement, and urges the presiding Administrative Law Judge and the Commission to approve the Settlement without modification.

Respectfully submitted,



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Counsel for UGI Central Penn Gas,
Inc.

Dated: August 23, 2011

APPENDIX E
(OTS Statement in Support)

1. On June 1, 2011, CPG filed copies of its definitive filing under Section 1307(f) of the Public Utility Code and said Commission regulations. The definitive filing proposed no change to the Company's existing Section 1307(f) rate placed into effect on June 1, 2011. On May 3, 2011, OTS filed its Notice of Appearance.

2. The subject filing was docketed by the Commission and assigned to Administrative Law Judge Kandace F. Melillo ("ALJ" or "ALJ Melillo"). On June 6, 2011, the ALJ issued a Prehearing Conference Order directing the submission of a prehearing conference memorandum by each party and establishing other parameters for the conduct of the Prehearing Conference. Upon subsequent request of OTS counsel, ALJ Melillo moved the previously established Prehearing Conference date to the later date of June 16, 2011.

3. Thus, on June 16, 2011, ALJ Melillo conducted a consolidated Prehearing Conference and subsequently issued an Order officially consolidating the 2011 Section 1307(f) cases of the three (3) affiliated UGI Companies - UGI Penn Natural Gas, Inc. at Docket No. R-2011-2238943; the instant CPG proceeding and UGI Utilities, Inc. - Gas Division at Docket No. R-2011-2238953 for purposes of hearing, but did not consolidate them for purposes of testimony, briefing, settlement petitions or a decision. The ALJ granted the petition to intervene at this docket filed by Central Penn Gas Large Users Group ("CPGLUG"), an association of large volume CPG transportation customers. The ALJ also granted petitions to intervene at this and the other two UGI related Section

1307(f) proceedings filed by CenterPoint, a licensed natural gas supplier in the Commonwealth of Pennsylvania that offers service to customers in the service territory of the UGI Companies.²

4. On June 22, 2011, ALJ Melillo issued an Order Granting Amended Petition for Protective Order wherein the ALJ concluded that that the issuance of a protective order providing for greater restrictions as to “highly confidential” competitive information has been justified as being necessary to avoid “severe and extreme prejudice.” That same date, a Protective Order was issued, as was issued last year in these cases, to provide for the sought after higher level of confidential protection.

5. OTS and the other active parties to this proceeding served several sets of interrogatories to CPG and timely responses were provided. Settlement discussions were held among the active parties regarding this and the other two proceedings. Those discussions eventually produced an agreement in principle on all issues among all parties to this proceeding and the parties informed the ALJ of that development.

² ALJ Melillo’s Procedural Order issued June 22, 2011, listed the following matters addressed at the Prehearing Conference: (1) identification of the UGI Companies’ filings; (2) consolidation of proceedings; (3) petitions to intervene; (4) admission pro hac vice of Jason F. Leif; (5) use of color coding for witness statements and briefs; (6) procedural schedule; (7) coordination of witnesses; (8) service requirements and parties list; (9) transcript turnaround; (10) need for public input hearings; (11) discovery modifications; and (12) need for a more restrictive protective order. Order, p. 2.

6. On August 5, 2011, the ALJ issued an Order Modifying Procedural Schedule and Providing for Settlement Procedures that accepted the parties proposal to submit a settlement document by the close of business on August 23, 2011.

7. On August 8, 2011, ALJ Melillo conducted a consolidated evidentiary hearing at which time the OTS testimonies at this docket were offered and admitted into the record by stipulation of the parties.³

8. Along with the other terms and conditions to the settlement agreed to by CPG to settle these this particular proceeding is a provision of particular interest to BI&E whereby CPG has agreed that in its PGC compliance filing in this proceeding, it will now reflect 50,000 Dth of annual projected Customer Choice volumes subject to the Migration Rider for the PGC Year beginning December 1, 2011, and will derive its E-Factor and Migration Rider using that 50,000 Dth projection. Stipulation, paragraph 27.

9. Based upon BI&E's analysis, acceptance of this proposed settlement is in the public interest for the following additional reasons:

a. Resolution of this case by settlement rather than litigation will avoid the substantial time and expense involved in continuing litigation of the issues in this proceeding. Specifically, this settlement has already eliminated the need for the cross-examination of witnesses, and has negated the need for the preparation of main

³ OTS Statement No. 1, the Direct Testimony of Debra Backer and OTS Statement No. 2-R, the Rebuttal Testimony of Michael Gruber had been previously distributed to the ALJ and the parties during the proceeding. Signed affirmations of both witnesses also accompanied their respective testimony introduced and admitted into the record at the hearing.

briefs, reply briefs, exceptions and reply exceptions, and potential appeals on matters contained in the settlement petition. BI&E respectfully submits that the avoidance of further and unnecessary rate case expense by settlement of this case serves the interests of both CPG and its customers.

b. BI&E agrees after review of the filing and extensive discovery and settlement discussions that the purchased gas cost recovery rates contained in the settlement are fair and reasonable. BI&E represents that the natural gas costs that CPG incurred during the historic period adhered to a least cost fuel procurement policy. A demonstrated least cost procurement policy benefits ratepayers as it ensures that the Company obtains gas at the most advantageous and available prices.

c. BI&E has concluded its analysis of the Company's E-factor and has determined that, consistent with the terms and conditions of the foregoing Stipulation, the resulting E-factor is calculated in accordance with established Commission practices. The E-Factor represents the interest associated with over-collection or under-collection of revenue based on the cost of purchased gas. The proper calculation of the E- Factor protects ratepayers by ensuring that the rates are adjusted appropriately to reflect the impact that these charges have on purchased gas costs.

d. BI&E reviewed the Company's projected gas costs and determined that they are reasonable projections. We note that the experienced costs are subject to review in a future Section 1307(f) proceeding and, as such, ratepayers are protected

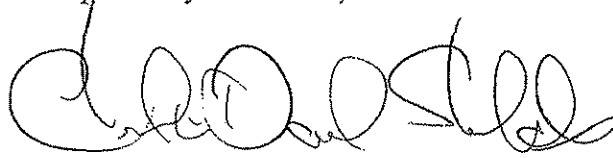
in that CPG gains no unwarranted financial advantages through its projected gas purchases and projected gas purchasing policies.

e. Commission acceptance of this settlement does not preclude future Commission investigation and/or litigation of CPG's fuel procurement policies, in accordance with the Commission's obligations mandated by 66 Pa.C.S. 1307(d) and (f) and other pertinent law.

f. The settlement establishes terms and conditions that BI&E considers to be in the public interest. However, in the event this matter proceeds to full litigation, BI&E is prepared to take positions that may differ from the terms of this settlement.

WHEREFORE, for the reasons set forth above, the Bureau of Investigation and Enforcement respectfully requests that Administrative Law Judge Mellilo and the Commission approve the Stipulation in Settlement of Section 1307(f) Rate Investigation in this present 2011 proceeding involving UGI Central Penn Gas, Inc., docketed at R-2011-2238949.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "Charles Daniel Shields", written over a horizontal line.

Charles Daniel Shields
Senior Prosecutor
PA Attorney ID No. 29363

Johnnie E. Simms
Chief Prosecutor
PA. Attorney ID No. 33911

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Dated: August 23, 2011

APPENDIX F
(OCA Statement in Support)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission :
 :
 v. : Docket No. R-2011-2238949
 :
 UGI Central Penn Gas, Inc. :

STATEMENT OF THE
OFFICE OF CONSUMER ADVOCATE
IN SUPPORT OF SETTLEMENT

The Office of Consumer Advocate (OCA), one of the signatory parties to the proposed Stipulation in Settlement of Section 1307(f) Rate Investigation (Settlement), finds the terms and conditions of the Settlement to be in the public interest for the following reasons:

I. INTRODUCTION

On April 29, 2011, pursuant to Sections 53.64 and 53.65 of the Commission's Rules and Regulations, UGI Central Penn Gas, Inc., (CPG or Company) submitted its pre-filing information in support of its annual reconciliation of purchased gas cost (PGC) rates. CPG's pre-filed information did not indicate the anticipated effect of the annual PGC reconciliation on existing rates. On May 11, 2011, the OCA filed its Formal Complaint in this matter.

The Company's filing was assigned to the Office of Administrative Law Judge and was further assigned to Administrative Law Judge Kandace F. Melillo (ALJ Melillo), for investigation and scheduling of hearings to determine whether the Company's gas costs comply with the standards set forth in the Public Utility Code.

On June 1, 2011, the Company made its definitive filing. The Company proposed a PGC rate of \$6.2704 per Dth for the residential class, which is no change from its current PGC rate.

On June 16, 2011, ALJ Melillo held a prehearing conference in this matter. A procedural schedule was established, and the parties agreed to certain modifications to the discovery rules on a going-forward basis.

As part of its investigation and analysis of the Company's filings, the OCA served multiple sets of discovery on CPG. On July 11, 2011, the OCA submitted the Direct Testimony of Jerome D. Mierzwa. That testimony set forth the OCA's recommendations as to: 1) CPG's design cold conditions and 2) CPG's proposal to issue RFPs for replacement interstate pipeline capacity. On July 25, 2011, the OCA also submitted the Rebuttal Testimony of Mr. Mierzwa. This testimony solely addressed the interstate pipeline capacity release and assignment provisions of CPG's customer choice program.

Settlement discussions were ongoing during this period of time, and resulted in the proposed Settlement of all outstanding issues. For the reasons set forth below, the OCA submits that the Settlement is in the public interest.

II. TERMS AND CONDITIONS OF THE SETTLEMENT

The following represents the terms of the Settlement that directly address all of the OCA's outstanding concerns in this case. The OCA expects that the other signatory parties will address those areas of the Settlement that apply to their issues.

Design Cold Provisions

In his Direct testimony, Mr. Mierzwa expressed his concerns that the design cold conditions utilized by CPG are too extreme (cold) and are, therefore, unreasonable. OCA St. 1 at

4-8. Specifically, CPG's design cold conditions represent a winter which is 25 percent colder than average. Id. at 7. Mr. Mierzwa recommended that that CPG use a winter season which is 10 percent colder than average for its winter season capacity planning purposes. Id. at 12. He stated that use of 10 percent colder than average conditions is consistent with the planning assumptions used by many other NGDCs, and is consistent with CPG's actual experience. Id.

Paragraph 31 and Appendix B of the Settlement address the OCA's concerns. Under the proposed settlement, CPG would adopt a new statistical procedure to calculate the design cold winter it uses for seasonal capacity planning purposes. That procedure is described in detail in Appendix B and results in the use of a winter which is on average 11 percent colder than normal for its three service territories. Settlement at ¶ 31. These design cold winters are more reasonable than the 25 percent colder than normal design winters CPG had been using for seasonal capacity planning purposes. The new design cold winter planning assumptions will reduce the amount of winter season capacity required by CPG, allowing CPG to reduce the number of days of peaking service it will seek through the RFP process from 11 days to 9 days. Settlement at ¶ 33. Although the amount is not quantifiable at this time, the reduction in the number of days of peaking service will reduce the demand charges paid by PGC customers.

Pipeline Contracting Issues

The final issue addressed by Mr. Mierzwa in his Direct Testimony dealt with CPG's proposal to issue RFPs for replacement interstate pipeline capacity. OCA St. 1 at 8-9. Mr. Mierzwa had the following concerns: (1) CPG's replacement contract quantities were, as explained above, based on its extreme winter season demand forecasts; (2) the RFP process was proposed to be conducted too early and with an unnecessarily limited response time; and (3)

CPG was including unnecessary provisions regarding no-notice service and hourly-adjustment of scheduled volumes. Id.

Settlement paragraphs 33 and 34 address the OCA's concerns in great length. The Settlement provides that, if it is determined that CPG's design peak day capacity is overstated, a portion of the contract quantities could be eliminated. Settlement at ¶ 34. Further, the settlement requires PNG to demonstrate through the RFP process that, if the Company ever increases its no-notice service beyond existing amounts, it must establish that the no-notice service is the least cost. Id. Finally, bidders will receive an extra week to submit their RFPs. Id.

Supplier Group Issues

In his Rebuttal testimony, Mr. Mierzwa addressed Supplier Group witness Crist's testimony regarding interstate pipeline capacity release and the assignment provisions of CPG's customer choice program. OCA St. 1-R at 1-7. Mr. Mierzwa had the following concerns with the Supplier Group testimony: (1) the proposal regarding direct assignment of storage capacity lacked the specificity required to ensure that impermissible cross-subsidization would not result; (2) the proposal regarding the pricing of released or assigned capacity was not consistent with the Commission's Competitive Markets Order; (3) the recommendation that choice suppliers only be assigned capacity sufficient to meet demands on an average day in January could result in inappropriate shifting of costs to PGC customers; and (4) the proposal that the release and assignment of pipeline capacity be voluntary is also inconsistent with the Commission's Competitive Markets Order. Id.

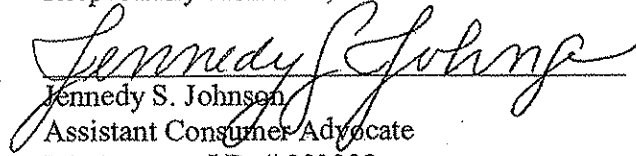
Settlement Paragraphs 37 to 40 focus on the Supplier Group's issues. These provisions address direct capacity assignment, notice dates for assignment capacity elections,

capacity release rates, and revenue sharing. Settlement at ¶¶ 37-40. These provisions ensure that PGC customers will not experience higher rates due to CPG's efforts to accommodate suppliers and shopping customers on its system. Further, Paragraph 40 states that the Supplier Group participants and their affiliates will not challenge CPG's direct assignment rule prior to June 1, 2013 and will not propose changes that would become operative before November 1, 2014. Settlement at ¶ 40. The OCA submits that these provisions are in the public interest and satisfy the OCA's concerns.

III. CONCLUSION

For the foregoing reasons, the Office of Consumer Advocate submits that the terms and conditions of the Settlement are in the public interest and therefore, should be approved.

Respectfully submitted,



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Date: August 23, 2011
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APPENDIX G
(OSBA Statement in Support)

The Stipulation

The *Stipulation* sets forth a comprehensive list of issues that were resolved through the negotiation process. The following issues were of significance to the OSBA when it concluded that the *Stipulation* was in the best interests of the Company's small business customers.

1) **Design Day Methodology** – In his rebuttal testimony, OSBA witness Robert D. Knecht discussed the issue of design day methodology, as follows:

One aspect of my investigation in this proceeding involved a review of the design day forecasting methodology for CPG and its affiliates, UGI Utilities Inc. (Gas Division) ('UGI Gas') and UGI Penn Natural Gas, Inc. ('PNG'). In its most recent base rates proceeding, CPG relied substantially on Commission approval of a design day demand forecast in a prior Section 1307(f) proceeding for developing allocation factors in its cost of service study ('COSS'). If CPG and its affiliates are going to rely on such Commission approvals from Section 1307(f) proceedings for developing rate class allocation factors in base rates proceedings, it becomes necessary for parties to evaluate class-specific implications of those estimates in these proceedings, where the underlying methodology can be more carefully evaluated. However, based on the lack of class-specific information available to me at present, I conclude that the Commission should give no weight to the Company's design day demand forecast from this proceeding in developing demand allocation factors in a future base rates proceeding.

OSBA Statement No. 1, at 1-2.

Moreover, the OSBA submitted a series of interrogatories to the Company in regard to the Company's design day methodology. *Id.*, at 1.

The *Stipulation* addresses this issue by assigning no precedential value to the design day forecast methodology used in this proceeding to establish the purchased gas cost ("PGC") rates. *Stipulation*, at Paragraph 36. *See also, Stipulation*, Paragraph 50. Consequently, in any future base rates proceeding, the Company will not be able to rely on this settlement for developing design day demand allocation factors. Instead, the Company will be required to make an

affirmative defense of its methodology in that proceeding. Thus, under the *Stipulation*, the OSBA will be able to fully evaluate the Company's design day forecast methodology and associated allocation factors in future Section 1307(f) and base rates proceedings.

2) **Supplier Group Issues** – This PGC proceeding involved considerable controversy regarding the Company's assignment of upstream pipeline, storage, and peaking capacity to retail Choice suppliers. As Mr. Knecht explained, mandatory assignment of upstream capacity may be necessary to avoid burdening the Company's sales customers with stranded capacity costs associated with customer migration to Choice service. OSBA Statement No. 1, at 2-3 ("The costs for this excess capacity (also known as 'stranded capacity') would then be borne by the remaining SOLR [supplier of last resort] customers, driving up the NGDC's purchased gas cost ('PGC') rates, and exacerbating the problems associated with the migration to competitive supply.").

A. Existing/Proposed Tariffs

Under the Company's proposed tariff, effective November 1, 2012, upstream capacity would be assigned in one of two ways. First, sufficient pipeline capacity would be assigned to each Choice supplier to meet its customers' peak demands. Second, pipeline capacity would be assigned to each Choice supplier to meet 59 percent of the Company's design day demands. For the other 41 percent, the Company would make winter sales to the Choice suppliers at average summer purchase prices. Under either capacity assignment approach, the Choice supplier would pay the weighted average cost of upstream transportation, storage, and peaking capacity.

Supplier Group Statement No. 1, at 6-8. *See also*, CPG Statement No. 3, at 8-9.

B. Supplier Group Proposal

The Supplier Group presented a set of alternative proposals which involved: (a) the assignment of transportation, storage, and peaking capacity to Choice suppliers; (b) the pricing of assigned capacity based on actual assigned capacity rather than all capacity; (c) the assignment of capacity based on average January day demand rather than peak day demand; (d) the assignment of capacity on a voluntary rather than mandatory basis; and (e) the sharing of all off-system sales and capacity release revenues with Choice suppliers as well as PGC customers. See Supplier Group Statement No. 1, at 5-6.

C. OSBA Position

In rebuttal, Mr. Knecht acknowledged that, in theory, the assignment of all types of upstream capacity would be beneficial to competition. However, he detailed the reasons why such assignment was impractical, and explained why the Supplier Group's proposal was not sufficiently detailed to be adopted in this proceeding. OSBA Statement No. 1, at 4-5.

Regarding the pricing of assigned capacity, Mr. Knecht did not object to the Supplier Group's proposal, but he noted that it might not work to the Choice supplier's advantage. OSBA Statement No. 1, at 6.

Regarding the amount of capacity to be assigned, Mr. Knecht explained that capacity assignment should be consistent with the obligations of the Choice suppliers under the Company's plan. OSBA Statement No. 1, at 7-8.

Regarding voluntary capacity assignment, Mr. Knecht explained that voluntary capacity assignment was inappropriate because it would unfairly leave PGC customers exposed to stranded costs. *Id.*, at 8-9.

Regarding the sharing mechanism, Mr. Knecht explained why allowing Choice suppliers

to share in capacity release revenues and off-systems sales margins was not appropriate because those margins are earned from capacity procured to serve PGC customers. *Id.*, at 9.

D. *Stipulation* – Capacity Assignment

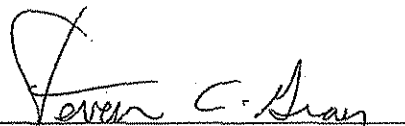
Consistent with Mr. Knecht's testimony, the *Stipulation* rejects all of the capacity assignment proposals by the Supplier Group, including the proposed change to the sharing of capacity release revenues and off-system sales margins. In exchange, the *Stipulation* adopts a modified sale mechanism that is purported to provide the Choice suppliers with greater flexibility in the timing of the winter sales (to better mimic the flexibility that Choice suppliers would have if storage capacity could be assigned), while retaining sensible protections for PGC ratepayers.

The OSBA takes no position on the capacity assignment portion of the *Stipulation*.

Conclusion

The OSBA takes no position on the *Stipulation* regarding capacity assignment. However, the OSBA respectfully requests that the ALJ and the Commission approve the remaining provisions of the *Stipulation*.

Respectfully submitted,



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For:

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Office of Small Business Advocate
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Harrisburg, PA 17101

Dated: August 23, 2011

APPENDIX H
(Supplier Group Statement in Support)

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**Before the Honorable Kandace F. Melillo,
Presiding Administrative Law Judge**

Pennsylvania Public Utility Commission, et al.	:	
	:	
v.	:	Docket No. R-2011-2238949
	:	
UGI Central Penn Gas, Inc.	:	

**STATEMENT IN SUPPORT OF SETTLEMENT OF
CENTERPOINT ENERGY SERVICES, INC.,
JEROME H. RHOADS, INC. D/B/A RHOADS ENERGY CORPORATION,
SHIPLEY ENERGY COMPANY and SHIPLEY CHOICE LLC**

CenterPoint Energy Services, Inc. (“CES”), Shipley Energy Company and Shipley Choice LLC (collectively “Shipley”), and Jerome H. Rhoads, Inc. d/b/a Rhoads Energy Corporation (“Rhoads”) (collectively “the Supplier Group”) hereby offer this Statement in Support of the Stipulation in Settlement of Section 1307(f) Rate Investigation that includes all parties to the above-captioned matter.

1. On June 1, 2011, UGI Central Penn Gas, Inc. (“CPG” or “the Company”) submitted its annual purchased gas cost (“PGC”) filing to the Pennsylvania Public Utility Commission (“the Commission”) pursuant to Section 1307(f) of the Public Utility Code, 66 Pa. C.S. § 1307(f).

2. CPG’s 1307(f) filing contained information on CPG’s proposed mandatory capacity assignment program, that requires natural gas suppliers (“NGSs”) operating on the CPG system to take assignment of, and to pay for, a level of pipeline capacity assets. The pipeline

capacity assets in question will be priced at the average weighted cost of all CPG's capacity assets, both base-load and peaking, as well as storage and other assets, even though no storage or peaking assets will be assigned. CPG's tariff currently provides options for assignment of pipeline capacity at a level calculated to be sufficient for an average January day. Beginning November 1, 2012, however, the pipeline capacity assignment escalates to a design peak day level of assets, which would increase the level of assets assigned and the associated costs significantly.

3. CES petitioned to intervene in the above-captioned case on June 8, 2011, and its petition was granted by order of the presiding Administrative Law Judge on June 22, 2011.

4. Shipley and Rhoads petitioned to intervene in the above-captioned case on June 28, 2011, and their petitions were granted by order of the presiding Administrative Law Judge on June 29, 2011.

5. The Supplier Group presented direct, rebuttal, and surrebuttal testimony in this case through its witness, James L. Crist, and actively engaged in settlement negotiations with all parties. The Supplier Group's concern in this matter has been focused on CPG's proposed mandatory capacity assignment program and the distribution of off-system sales revenues.

6. The Supplier Group's testimony presented five main points: (1) capacity assigned to Choice suppliers should include all interstate pipeline transportation and storage capacity that was procured to serve a Choice supplier's customers; (2) the price charged for assigned capacity should be derived from the actual contract rate for the assigned capacity, not a weighted average cost of all capacity that the Company has acquired, which includes capacity that has no connection to an NGS's customers; (3) the derivation of the capacity assigned to a natural gas supplier should be based on the average day in the month of highest usage on the Company's

system, and an NGS's capacity assignment should equate to its proportional share of the actual capacity CPG has under contract so that CPG does not over or under allocate its actual capacity; (4) the Company's capacity assignment program should be voluntary; and (5) the 75% customer share of off-system sales revenues should be credited to both PGC customers and Choice customers on a proportionate basis.

7. In discussing these five points, the Supplier Group, through its witness, expressed the position that CPG's proposed capacity assignment program is not in compliance with the Natural Gas Choice and Competition Act and corresponding Commission orders requiring that capacity assignments be made on a non-discriminatory basis and that transportation and storage assets should follow the shopping customers because (1) the Company does not plan to release the same mix of system assets to Choice suppliers that it uses to supply the needs of the sales customers; (2) the Company allocates the costs that Choice suppliers must pay for the capacity that CPG does plan to release (interstate pipeline capacity), based on peak day requirements, even though CPG did not purchase that capacity for peaking purposes to begin with, but rather purchased that capacity for base load purposes, to meet the system's average day in the coldest month; and (3) the Company plans to charge the weighted average demand cost of all CPG PGC capacity, storage, and peaking assets, yet releases only the interstate pipeline capacity. In addition, 66 Pa. C.S. § 2204(d) and (e) provide that NGSs cannot be assigned capacity for contracts that were entered into or renewed after the Company's restructuring filing, unless the Company has followed a specific review and approval process, which is outlined in § 2204(e). Because the Company has not specified what assets it plans to assign, the Supplier Group explained that it could not confirm that these statutory requirements have been met.

8. Although the Settlement does not adopt the allocation of both pipeline capacity and storage assets approach that the Supplier Group proposed, the Settlement includes changes to CPG's proposed capacity assignment program that improve it. These changes should provide NGSs with flexibility that they do not have under the proposed CPG capacity assignment program. First, the Company has agreed to modify the bundled sale option in its proposed tariff to allow for daily withdrawal flexibility, effective November 1, 2012. Under this approach, Choice suppliers will be able to purchase natural gas from CPG on a monthly basis in a manner that is comparable to the bundled sales program that is presently proposed by CPG. The improvement to this program that was agreed upon is that instead of requiring that a Choice supplier take gas purchased under this program on a daily, ratable basis during the course of the winter, under the revised approach, a participating Choice supplier can vary its gas receipts on a daily basis from zero Dth up to a maximum daily quantity based on the Choice supplier's daily delivery requirement ("DDR"), with the requirement that the Choice supplier take a fixed monthly quantity by the end of the month. This approach provides Choice suppliers participating in this program with some (although not all) of the flexibility that a supplier would have if it controlled storage itself. Thus, while this approach is not entirely comparable to storage capacity assignment, it provides the Choice suppliers with some additional flexibility.

9. In addition, the Settlement provides that bundled sale quantities not purchased by NGSs by the end of the month will be purchased by the PGC. The fixed monthly bundled sale quantities will be based on the current storage withdrawal plan for CPG, updated annually, and communicated as a percentage of each Choice supplier's pre-month normalized delivery requirements. The maximum daily quantities for the bundled sale will be determined based on the daily delivery flexibility of the Company's storage assets. The percentage of Choice capacity

release associated with firm transportation contracts will be modified based on the impact of changing the daily flexibility of bundled sales quantities.

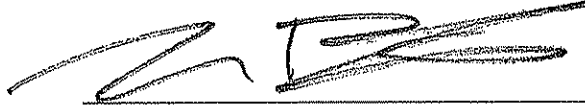
10. The DDR Variation Percentage is the sum of the actual DDRs experienced by a Choice supplier divided by the sum of the pre-month average DDRs that was used to calculate the fixed monthly bundled sales quantity, converted to percentage. For any month where the DDR Variation Percentage is greater than ninety percent (90%), the index used for bundled sale cash-ins is 0.9 times the lowest Henry Hub price for the applicable month of flow. In the case where the DDR Variation Percentage is less than or equal to ninety percent (90%), an alternative production area index applies. This represents a compromise by the Supplier Group for purposes of achieving settlement.

11. The Settlement also provides that Choice suppliers will be required to purchase from the Company a separate bundled sale on peak days when, in the winter, the Choice supplier's DDR exceeds the sum of the released firm capacity and the maximum daily quantity associated with the bundled sale up to the Choice supplier's peak daily delivery requirement.

12. The Supplier Group believes that the Settlement is a reasonable compromise between themselves and the other parties. This Settlement provides NGSs with additional flexibility, which will be achieved using storage assets, thereby making the allocation of certain storage costs to the NGSs more appropriate than in the capacity assignment approach originally proposed by CPG. Although the Supplier Group continues to believe, as a general matter, that any assignment of capacity should include a bundle of all the assets used to serve customers, including storage assets, and that those assets should follow a customer, the approach achieved in the Settlement is a reasonable compromise that should be adopted.

13. For the foregoing reasons, the Supplier Group respectfully requests that the Commission approve the Settlement as filed.

Respectfully submitted,



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DATED: August 22, 2011

APPENDIX I
(CPGLUG Letter of Non-Opposition)



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August 23, 2011

Honorable Kandace F. Melillo
Administrative Law Judge
Pennsylvania Public Utility Commission
400 North Street, 2nd Floor West
Harrisburg, PA 17120

RE: Pennsylvania Public Utility Commission v. UGI Central Penn Gas, Inc.;
Docket No. R-2011-2238949

Dear Judge Melillo:

Central Penn Gas Large Users Group ("CPGLUG"), an intervenor in this proceeding, hereby submits this letter to indicate that it neither supports nor opposes the Stipulation in Settlement of Section 1307(f) Rate Investigation in the above-referenced proceeding.

Please feel free to contact us with any questions regarding this letter. Thank you.

Very truly yours,

McNEES WALLACE & NURICK LLC

By *Vasiliki Karandrikas*
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VK/sds
Enclosure

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