

COMMONWEALTH OF PENNSYLVANIA



DARRYL A. LAWRENCE
Consumer Advocate

OFFICE OF CONSUMER ADVOCATE
555 Walnut Street, 5th Floor, Forum Place
Harrisburg, Pennsylvania 17101-1923
(717) 783-5048
(800) 684-6560

 @pa_oca
 /pennoca
FAX (717) 783-7152
consumer@paoca.org
www.oca.pa.gov

August 26, 2025

Via Electronic Filing

Secretary Matthew L. Homsher
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission
v.
Columbia Gas of Pennsylvania, Inc.
Docket No. R-2025-3053499

Dear Secretary Homsher:

Attached for electronic filing please find the Office of Consumer Advocate's Main Brief in the above-referenced proceeding. Please note that the **CONFIDENTIAL** version of OCA's Main Brief will only be sent to the parties that have executed the non-disclosure agreement as indicated on the Certificate of Service. The **CONFIDENTIAL** version of the OCA's Main Brief will be efiled using the Public Utility Commission's Share Point file process.

Copies have been served on the parties as indicated on the enclosed Certificate of Service.

Respectively,

/s/ Christy Appleby
Christy Appleby
Senior Assistant Consumer Advocate
PA Attorney I.D. # 85824
CAappleby@paoca.org

Enclosures

cc: Administrative Law Judge Jeffrey A. Watson (Via Email: jeffwatson@pa.gov)
Administrative Law Judge Chad Allensworth (Via Email: callenswor@pa.gov)
OSA (Via Email: ra-osa@pa.gov)
Certificate of Service

CERTIFICATE OF SERVICE

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3053499
	:	
Columbia Gas of Pennsylvania, Inc.	:	
	:	

I hereby certify that I have this day filed electronically on the Commission's electronic filing system and served a true copy of the following document, the Office of Consumer Advocate's Public Main Brief (redacted) and the Confidential Main Brief (unredacted), upon parties of record in this proceeding in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant), in the manner and upon the persons listed below.

Dated this 26th day of August 2025.

(*) Can receive CONFIDENTIAL Main Brief

SERVICE BY E-MAIL ONLY

Steven C. Gray, Esq. *
Rebecca Lyttle, Esq. *
Office of Small Business Advocate
555 Walnut Street
1st Floor, Forum Place
Harrisburg, PA 17101-1923
sgray@pa.gov
relyttle@pa.gov
Counsel for OSBA

Michael W. Hassell, Esq. *
Megan E. Rulli, Esq. *
Anthony D. Kanagy, Esq. *
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101
mhassell@postschell.com
mrulli@postschell.com
akanagy@postschell.com
Counsel for Columbia

Scott B. Granger, Esq. *
Adam J. Williams, Esq. *
Bureau of Investigation & Enforcement
Pennsylvania Public Utility Commission
400 North Street, 2nd Floor
Harrisburg, PA 17120
sgranger@pa.gov
adawilliam@pa.gov
Counsel for I&E

Elizabeth R. Marx, Esq.
John W. Sweet, Esq. *
Ria M. Pereira, Esq. *
Lauren N. Berman, Esq. *
118 Locust Street
Harrisburg, PA 17101
pulp@pautilitylawproject.org
Counsel for CAUSE-PA

Whitney E. Snyder, Esq. *
Thomas J. Sniscak, Esq.
Erich W. Struble, Esq. *
501 Corporate Circle, Suite 302
Harrisburg, PA 17110
wesnyder@hmslegal.com
tjsniscak@hmslegal.com
ewstruble@hmslegal.com
Counsel for PSU

James L. Crist *
Lumen Group, Inc.
4226 Yarmouth Drive, Suite 101
Allison Park, PA 15101
JLCrist@aol.com
Consultant for PSU

Emily Farah, Esq. *
NiSource Corporate Services Co.
121 Champion Way, Suite 100
Canonsburg, PA 15317
efarah@nisource.com
Counsel for Columbia

Candis A. Tunilo, Esq. *
NiSource Corporate Services Co.
800 N. Third St., Suite 204
Harrisburg, PA 17102
ctunilo@nisource.com
Counsel for Columbia

Joseph L. Vullo, Esq.*
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com
*Counsel for Pennsylvania Weatherization
Providers Task Force*

Mark Ewen
Industrial Economics, Incorporated
2067 Massachusetts Avenue
Cambridge, MA 02140
mewen@indecon.com
Witness for OSBA

Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
Phone: 717-783-5048
Fax: 717-783-7152

Dated: August 26, 2025

Counsel for:
Darryl A. Lawrence
Consumer Advocate

/s/ Christy Appleby

Christy Appleby
Senior Assistant Consumer Advocate
PA Attorney I.D. # 85824
CAappleby@paoca.org

Jacob D. Guthrie
Assistant Consumer Advocate
PA Attorney I.D. # 334367
jguthrie@paoca.org

Barrett C. Sheridan
Assistant Consumer Advocate
PA Attorney I.D. # 61138
BSheridan@paoca.org

Harrison W. Breitman
Assistant Consumer Advocate
PA Attorney I.D. # 320580
HBreitman@paoca.org

OAColumbiaGas2025@paoca.org

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2025-3053499
	:	
Columbia Gas of Pennsylvania, Inc.	:	
	:	

MAIN BRIEF
OF THE
OFFICE OF CONSUMER ADVOCATE

PUBLIC VERSION

Christy M. Appleby
Senior Assistant Consumer Advocate
PA Attorney I.D. # 85824
CAppleby@paoca.org

Harrison W. Breitman
Assistant Consumer Advocate
PA Attorney I.D. # 320580
HBreitman@paoca.org

Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
Phone: 717-783-5048
Fax: 717-783-7152

Date: August 26, 2025

Jacob Guthrie
Assistant Consumer Advocate
PA Attorney I.D. # 334367
JGuthrie@paoca.org

Counsel for:
Darryl A. Lawrence
Consumer Advocate

TABLE OF CONTENTS

I. INTRODUCTION	1
A. Description of the Office of Consumer Advocate.....	1
B. Procedural History.....	2
C. Legal Standards	4
1. Utility Monopoly Regulation	4
2. Burden of Proof	5
3. Just and Reasonable and Not Unduly Discriminatory Rates.....	8
4. Reasonable Opportunity to Earn a Fair Rate of Return.....	10
5. Adequate Quality of Service to Be Observed.....	12
6. Alternative Ratemaking Mechanisms.....	14
7. Due Consideration to the Interest of Consumers.....	17
D. Statement of the Case	17
1. Overview of the Filing.....	17
2. Summary of Public Input Hearing Testimony.....	18
II. SUMMARY OF ARGUMENT	27
III. OVERALL POSITION ON RATE INCREASE.....	36
A. Overall Position on Rate Filing	36
B. Overall Position on Revenue Requirement	42
IV. RATE BASE.....	43
A. Plant in Service – Inflation Adjustment.	43
B. Accumulated Depreciation	46
C. Cash Working Capital	49
D. Accumulated Deferred Income Taxes (ADIT).....	50
E. Materials & Supplies/Prepayments	51
F. Consolidated Income Tax Adjustment	52

G. Conclusion.....	54
V. REVENUES.....	55
VI. DEPRECIATION EXPENSE.....	55
VII.O&M AND A&G EXPENSES.....	88
A. Inflation Adjustments	89
B. Labor.....	91
C. Incentive Compensation	94
D. Restricted Stock and Long Term Incentive (LTI)	97
E. Other Employee Benefits	99
F. Outside Services	100
G. Corporate Insurance.....	101
H. Injury and Damages.....	102
I. Employee Expenses.....	102
J. Company Memberships.....	105
K. Utilities – Fuel Used in Company Operations.....	107
L. Advertising	107
M. NiSource Corporate Services Company (NCSC) Shared Services.....	110
1. Long-Term Incentive (LTI) Compensation.....	111
2. Supplemental Executive Retirement Plan	113
3. Short-Term Incentive (STI) Compensation.....	114
N. Diversity, Equity, and Inclusion (DEI) Expense.....	114
O. Rate Case Expense	115
P. Uncollectible Expense	117
Q. Rider Universal Service Plan (USP)	118
R. Depreciation and Amortization Expense.....	119
S. Conclusion Regarding Expenses	120

VIII. TAXES	120
A. Income Taxes.....	120
B. Taxes Other Than Income Tax	122
IX. RATE OF RETURN	123
A. Introduction	123
B. Columbia’s proposed capital structure strays significantly from Columbia’s proposed proxy group.....	124
C. Debt Cost Rate.....	126
D. The OCA’s recommended return on common equity is supported by substantial evidence and results in just and reasonable rates.	126
1. Mr. Garrett’s Discounted Cash Flow model is reasonable and supported by substantial evidence.....	127
a. OCA witness Garrett’s Analyst Growth Rate DCF relies on Value Line’s publication without modification.....	128
b. OCA witness Garrett’s Sustainable Growth Rates DCF is reasonably based on the U.S. Gross Domestic Product growth.....	129
c. OCA witness Garrett’s DCF model relies on data from financial institutions without alteration while Columbia witness Rea’s DCF analysis subjectively overstates the appropriate rate of return.	131
2. Capital Asset Pricing Model.....	133
a. OCA witness Garrett’s Risk Free Rate is reasonably based on U.S. Treasury securities.	134
b. OCA witness Garrett’s beta is the most recent Value Line beta.	135
c. OCA witness Garrett appropriately relied on expert surveys and an implied equity risk premium based on respected financial institutions and scholars.....	136
d. Conclusion as to the OCA’s CAPM recommendation.	137
e. Response to Mr. Rea’s CAPM analysis and other issues.	138
i. Mr. Rea’s CAPM Beta is Outdated.....	138
ii. Mr. Rea’s Equity Risk Premiums are excessive.	139

iii. Mr. Rea’s size premium adjustment is unreasonable.....	140
iv. Mr. Rea’s additional Risk Premium Model significantly overestimates the cost of equity.	141
E. Management Performance Premium.....	141
1. Columbia’s performance does not merit the granting of a 25 basis point performance management adder.....	141
2. Columbia’s management performance regarding low-income customers has not been superior and does not merit a management performance adder.	143
a. LIHEAP Performance.....	143
b. Columbia Gas’s efforts to serve its low-income customers have not been exemplary as demonstrated by the BCS Universal Services report.	145
c. Columbia’s customer service performance also fails to achieve superior performance.	163
i. Call Center Performance.....	164
ii. Customer Satisfaction Surveys	168
iii. J.D. Power Customer Satisfaction Survey	169
3. Conclusion.....	170
X. REVENUE ALLOCATION AND RATE DESIGN	171
A. Cost of Service Study	172
1. The results of the Company’s P&A ACOS are reasonable and should be given significant weight.....	174
2. The Customer-Demand ACOS is unsupported by cost causation principles and Commission precedent and should be given no weight.	176
B. Revenue Allocation	179
1. Rate LDS/LGSS are currently underpaying their cost of service and the revenue allocation adopted in this proceeding should move them closer to their cost of service than proposed by Columbia.	183
2. The revenue allocation selected by the Commission should move customer classes overpaying their indicated cost of service to the same	

RROR instead of moving them towards their cost of service by the same amount.	186
C. Rate Design/Tariff Structure	189
1. Columbia’s residential customer charge is inconsistent with cost causation principles.	191
2. Columbia’s residential customer charge is inconsistent with gradualism... ..	195
3. Columbia’s residential customer charge exacerbates affordability concerns.	197
4. Columbia’s residential customer charge reduces incentives to pursue energy efficiency and conservation.	201
5. Overall, Columbia’s proposed residential customer charge should be denied and the evidence presented by the OCA, I&E, and CAUSE-PA regarding the residential customer charge should be given greater weight.	202
D. Summary and Alternatives	204
XI. ALTERNATIVE RATEMAKING.....	205
A. Weather Normalization Adjustment.....	205
1. Columbia’s WNA has operated in the past 10 years to extract additional revenues from its customers without providing commensurate benefits to the customers subjected to the WNA.	205
1. Columbia’s proposed permanent WNA fails to satisfy the Commission’s stated policy factors for approval of alternative ratemaking mechanisms. .	209
2. Columbia’s proposed WNA is disfavored by Columbia’s customers due to their experience under the WNA Pilot.	223
3. Columbia’s use of the FPFTY and DSIC and its frequent filing demonstrate that it does not need the proposed WNA to earn sufficient revenue.	225
4. The proposed WNA’s departure from principles of cost causation is unwarranted and unsupported.	226
5. The proposed WNA disincentivizes conservation and energy efficiency by customers because the WNA captures customers’ bill savings earned through their reduced usage.....	230

6. Columbia’s proposed WNA disproportionately harms the Company’s low-income customers.	233
7. Overall, Columbia has failed to meet its burden of proof that the proposed WNA is a just and reasonable rate.	238
B. Revenue Normalization Adjustment	242
1. The Company’s proposed RNA would not result in just and reasonable rates.....	242
1. The proposed RNA is deficient under the Commission’s policy factors.	246
2. The proposed RNA presents no potential benefit to Columbia’s customers and is likely to result in increased rates.....	258
3. Columbia is not entitled to a guarantee of recovering its costs and the RNA eliminates the Company’s incentive to control its costs between rate cases.	262
4. The proposed RNA is contrary to cost causation because it recovers demand- and throughput-related costs as a fixed, unavoidable charge.....	266
5. The proposed RNA is likely to produce a disincentive for customer conservation and energy efficiency because avoided distribution charges in one year results in RNA charges the following year; the RNA captures customers’ bill savings earned through their reduced usage.	268
6. Overall, Columbia has failed to meet its burden of proof that the RNA is a just and reasonable rate.....	270
XII.CUSTOMER/QUALITY OF SERVICE ISSUES.....	273
A. Columbia should perform a root cause analysis to address customer disputes....	274
B. Columbia should perform an analysis of payment arrangement policies and termination and reconnection policies.	278
C. Columbia Billing and Payment Policies.....	283
1. Columbia should ensure that appropriate billing disclosures and notifications are provided for Natural Gas Suppliers.	283
2. Columbia Website and Automated Service Offerings	285
XIII. UNIVERSAL SERVICE PROGRAMS.....	287
A. Introduction	287

B. The Commission must consider as a part of this rate request the overall affordability of Columbia’s rates.	289
C. The Commission must also consider the impact on affordability for low-income households.	292
D. In reaching its final determination as to a revenue requirement in this matter, the Commission should consider disproportionate impact of inflation on low-income customers.	298
E. The Commission should consider the impact of setting a revenue requirement on moderate income ALICE households.	300
F. The Cost-of-Living in Columbia’s service territory can impact affordability for ratepayers.	302
G. Recommendations to Address Low-Income Unaffordability	304
1. Introduction	304
2. Columbia should implement changes to improve its identification of low-income customers.	305
3. Columbia should take more effective actions to use the universal service program to prevent disconnection of service for nonpayment to Confirmed Low-Income customers.	309
4. Columbia’s proposed arrearage forgiveness pilot should be approved.	316
5. Columbia’s proposal to change the cost recovery for CARES and CAP administrative costs should be denied.	317
6. Conclusion	321
XIV. ENERGY EFFICIENCY PROGRAMS	322
A. Introduction	322
B. In its Rebuttal Testimony, the Company adopted, in full or in part, several of OCA witness Sherwood’s recommendations.	326
1. Market Data	326
2. Residential Prescriptive Program	329
C. An independent third-party evaluator should be hired to complete evaluations of the program.	333
D. Conclusion	335

XV. COMPETITIVE SUPPLY ISSUES	336
XVI. TARIFF ISSUES (NOT ADDRESSED ABOVE).....	336
A. Rate EDDS	336
B. Eligible Customer Lists	337
XVII. MISCELLANEOUS ISSUES	342
XVIII. CONCLUSION	343

Appendix A –	OCA Rate Case Tables
Appendix B –	OCA Proposed Findings of Fact, Conclusions of Law, and OCA Proposed Ordering Paragraphs
Appendix C –	OCA Testimony and Exhibits Entered into Evidence
Appendix D –	Re Minnegasco Inc. Case

TABLE OF AUTHORITIES

	Page(s)
Cases	
<i>Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm’n</i> , 461 U.S. 375 (1983).....	4
<i>Atlantic Ref. Co. v. Pub. Serv. Comm’n</i> , 360 U.S. 378 (1981).....	11
<i>Bell Atl. – Pa., Inc. v. Pa. PUC</i> , 672 A.2d 352 (Pa. Cmwlth. 1995)	16, 205, 206
<i>Berner v. Pa. PUC</i> , 116 A.2d 738 (Pa. 1955)	6
<i>Bluefield Water Works and Improvement Co. v. Public Serv. Comm’n of W.Va.</i> , 262 U.S. 679 (1923)	10, 270
<i>Burleson v. Pa. PUC</i> , 461 A.2d 1234 (Pa. 1983)	5, 6, 44, 206
<i>Citizens Water Co. v. Pa. PUC</i> , 124 A.2d 123 (Pa. Super. 1956).....	41
<i>City of Lancaster Sewer Fund v. Pa. PUC</i> , 793 A.2d 978 (Pa. Cmwlth. 2002)	8, 9
<i>Dee-Dee Cab, Inc. v. Pa. PUC</i> , 817 A.2d 593 (Pa. Cmwlth. 2003)	270
<i>Duquesne Light Co. v. Barasch</i> , 488 U.S. 299 (1989)	11
<i>Federal Power Comm’n v. Hope Natural Gas Co.</i> , 320 U.S. 591 (1944)	<i>passim</i>
<i>HIKO Energy, LLC v. Pa. PUC</i> , 163 A.3d 1079 (Pa. Cmwlth. 2017) <i>aff’d</i> by <i>HIKO Energy, LLC v. Pa.</i> <i>PUC</i> , 209 A.3d 246 (Pa. 2019)	16
<i>Hoover v. Pa. R.R.</i> , 27 A. 282 (Pa. 1893)	180

<i>Jenkins Twp. v. Pub. Serv. Comm’n</i> , 65 Pa. Super. 122, 1916 Pa. Super. LEXIS 30 (Pa. Super. 1916)	5
<i>Lansberry v. Pa. PUC</i> , 578 A.2d 600 (Pa. Cmwlt. 1990)	5, 6
<i>Lindheimer v. Illinois Bell Tel. Co.</i> , 292 U.S. 151 (1934)	<i>passim</i>
<i>Lloyd v. Pa. PUC</i> , 904 A.2d 1010 (Pa. Cmwlt. 2006)	<i>passim</i>
<i>Lower Frederick Twp. Water Co. v. Pa. PUC</i> , 409 A.2d 505 (Pa. Cmwlt. 1980)	5
<i>McCloskey v. Pa. PUC</i> , 195 A.3d 1055 (Pa. Cmwlt. 2018)	17
<i>McCloskey v. Pa. PUC</i> , 225 A. 3d 192 (Pa. Cmwlt. 2020)	225
<i>Munn v. Illinois</i> , 94 U.S. 113 (1877)	4
<i>Nat’l Fuel Gas Dist. Corp. v. Pa. PUC</i> , 464 A.2d 546 (Pa. Cmwlt. Ct. 1983)	264, 265
<i>Nat’l Fuel Gas Dist. Corp. v. Pa. PUC</i> , 677 A.2d 861 (Pa. Cmwlt. 1986)	44
<i>Nat’l Utils. v. Pa. PUC</i> , 709 A.2d 972 (Pa. Cmwlt. 1998)	12, 274
<i>Pa. Elec. Co. v. Pa. PUC</i> , 502 A.2d 130 (Pa. 1985)	263
<i>Pa. Power & Light Co. v. Pa. Pub. Util. Com.</i> , 311 A.2d 151 (Pa. Cmwlt. 1973)	62
<i>Penn Sheraton Hotel v. Pennsylvania Public Utility Com.</i> , 198 Pa. Super. 618 (Pa. Super. 1962)	56, 57
<i>Pennsylvania Gas & Water Co. v. Pa. PUC</i> , 341 A.2d 239 (Pa. Cmwlt. 1975)	10
<i>Permian Basin Area Rate Cases</i> , 390 U.S. 747 (1968)	11, 79

<i>Phila. Elec. Co. v. Pa. PUC</i> , 470 A.2d 654 (Pa. Cmwlth. 1984)	180
<i>Phila. Elec. Co. v. Pa. PUC</i> , 552 A.2d 342 (Pa. Cmwlth. 1989)	89
<i>Phila. Indus. and Comm. Gas Users Group v. Pa. PUC</i> , 2025 Pa. Commw. LEXIS 133 (Pa. Cmwlth. Aug. 1, 2025)	172, 227, 267
<i>Phila. Suburban Transp. Co. v. Pa. PUC</i> , 281 A.2d 179 (Pa. Cmwlth. 1971)	41
<i>Pittsburgh v. Pa. Pub. Util. Comm’n</i> , 222 A. 2d 395 (Pa. Super. 1966)	62
<i>Pittsburgh v. Pa. PUC</i> , 126 A.2d 777 (Pa. Super 1956)	239, 287
<i>Pittsburgh v. Pa. PUC</i> , 128 A.2d 372 (Pa. Super. 1956)	37, 38
<i>Pittsburgh v. Pa. PUC</i> , 69 A.2d 844 (Pa. Super Ct. 1949)	262
<i>Pittsburgh v. Pa. PUC</i> , 82 A.2d 515 (Pa. Super. 1951) <i>otherwise modified in Pittsburgh v. Pa. PUC</i> , 88 A.2d 59 (Pa. 1952)	41
<i>Popowsky v. Pa. PUC</i> , 665 A.2d 808 (Pa. 1995)	8
<i>Popowsky v. Pa. PUC</i> , 674 A.2d 1149 (Pa. Cmwlth. 1996)	9, 116
<i>Popowsky v. Pa. PUC</i> , 683 A.2d 958 (Pa. Cmwlth. 1996)	8
<i>Popowsky v. Pa. PUC</i> , 869 A.2d 1144 (Pa. Cmwlth. 2005) <i>alloc. denied Popowsky v. Pa. PUC</i> , 895 A.2d 552 (Pa. 2006)	255
<i>Relief Elec. Light, Heat & Power Co's. Petition</i> , 63 Pa. Super 1, 6-11, 1916 Pa. Super. LEXIS 89 (Pa. Super. 1916)	5
<i>Riverton Consol. Water Co. v. Pa. PUC</i> , 140 A.2d 114 (Pa. Super. 1958)	125

<i>University of Pa. v. Pa. PUC,</i> 485 A.2d 1217 (Pa. Cmwlt. 1984)	6
<i>Victory Bank v. Commonwealth,</i> 190 A.3d 782 (Pa. Cmwlt. 2018)	66
<i>West Penn Power Co. v. Pa. PUC,</i> 578 A.2d 75 (Pa. Cmwlt. Ct. 199)	273
<i>Zucker v. Pa. PUC,</i> 401 A.2d 1377 (Pa. Cmwlt. 1979)	206
<i>Zucker v. Pa. PUC,</i> 402 A.2d 1377 (Pa. Cmwlt. 1979)	9
Administrative Decisions	
<i>Columbia Gas of Pennsylvania, Inc. Universal Service and Energy</i> <i>Conservation Plan for 2024-2028 Submitted in Compliance with 52 Pa.</i> <i>Code § 62.4, Docket No. M-2023-3039487, Order (April 2024).</i>	314
<i>Guidelines for Eligible Customer Lists,</i> Docket No. M-2010-2183412, Order (March 13, 2025)	35, 338
<i>Laura Andracchio Johnson and Charles Johnson v. Duquesne Light Co.,</i> Docket No. C-2022-3032695, 2023 PA. PUC LEXIS 343, Order (Dec. 21, 2023)	273
<i>Pa. PUC v. Aqua Pa., Inc.,</i> Docket No. R-00038805, 2004 Pa. PUC LEXIS 39 (Order entered July 23, 2004)	192
<i>Pa. PUC v Aqua Pa. Water Co.,</i> 2022 Pa. PUC LEXIS 161 (Order entered May 16, 2022)	45, 95, 133
<i>Pa. PUC v. Columbia Gas of Pa. Inc.,</i> Docket No. G-2025-3056022, Letter (June 30, 2025)	341, 342
<i>Pa. PUC v. Columbia Gas Co.,</i> Docket No. R-2019-3010039, Order (Oct. 3, 2019)	289
<i>Pa. PUC v. Columbia Gas Co.,</i> Docket No. R-2020-3018835, Order (April 15, 2021)	9, 289
<i>Pa. PUC v. Columbia Gas Co.,</i> Docket No. R-2021-3024296, Order (Dec. 16, 2021)	289

<i>Pa. PUC v. Columbia Gas Co.,</i> Docket No. R-2022-3031211, Order (Dec. 8, 2022)	289
<i>Pa. PUC v. Columbia Gas of Pa.,</i> Docket No. R-2022-3032167, 2023 PA. PUC LEXIS 173 (Order entered June 15, 2023)	105
<i>Pa. PUC v. Columbia Gas of Pa., Inc.,</i> Docket No. R-2010-2215623 (Order entered Oct. 14, 2011)	228
<i>Pa. PUC v. Columbia Gas of Pa., Inc.,</i> Docket No. R-2024-3046519 (Joint Petition for Settlement filed Aug. 28, 2024)	<i>passim</i>
<i>Pa. PUC v. Columbia Water Co.,</i> 2009 Pa. PUC LEXIS 1423 (2009)	116
<i>Pa. PUC v. Columbia Water Co.,</i> Docket No. R-2023-3040258 (Order entered Jan. 18, 2024)	117
<i>Pa. PUC v. Duquesne Light Co.,</i> Docket No. R-2021-3024750, Order (Dec. 16, 2021)	274
<i>Pa. PUC v. Equitable Gas Co.,</i> 57 Pa. PUC 423 (1983)	6, 95
<i>Pa. PUC v. Nat’l Fuel Gas Dist. Corp.,</i> 73 Pa. PUC 552 (1990)	12
<i>Pa. PUC v. National Fuel Gas Distribution Corp.,</i> 84 Pa. PUC 134 (1995)	116
<i>Pa. PUC v. NFGD,</i> 1994 Pa. PUC LEXIS 135 (Oct. 7, 1994)	76, 77
<i>Pa. PUC v. PPL Electric Utilities Corporation,</i> Docket No. R-2012-2290597 (Order entered Dec. 5 2012)	192, 230
<i>Pa. PUC v. PPL Gas Utilities Corporation,</i> Docket No. R-00061398, 2007 Pa. PUC LEXIS 2 (Order entered Feb. 8, 2007)	44, 192
<i>Pa. PUC v. Pa.-American Water Co.,</i> 2021 PA. PUC LEXIS 55 (Feb. 25, 2021)	95, 96

<i>Pa. PUC v. Pa.-American Water Co.,</i> 231 P.U.R.4th 277, 2004 Pa. PUC LEXIS 29 (Jan. 29, 2004)	6
<i>Pa. PUC v. Pa.-American Water Co.,</i> Docket No. R-00038304, 2003 Pa. PUC LEXIS 498 (Order entered Nov. 26, 2003)	106, 108, 109
<i>Pa. PUC v. Pa.-American Water Co.,</i> Docket Nos. R-2023-3043189 <i>et al</i> (Order entered July 22, 2024).....	206
<i>Pa. PUC v. Pa. Gas & Water Co.,</i> 74 PUR4th 238 (1986)	273
<i>Pa. PUC v. Pa. Power & Light Co.,</i> 85 Pa. PUC 306 (1995)	93
<i>Pa. PUC v. Pa. Power Co.,</i> 55 Pa. PUC 552 (1982)	<i>passim</i>
<i>Pa. PUC v. PECO Energy Co. – Gas Div.,</i> Docket No. R-2020-3018929 (Order entered June 17, 2021).....	230
<i>Pa. PUC v. PECO Energy Company – Gas Division,</i> Docket No. R-2024-3046932 (Order entered Dec. 12, 2024)	206
<i>Pa. PUC v. Phila. Elec. Co.,</i> 58 Pa. P.U.C. 7 (1983)	44
<i>Pa. PUC v. Phila. Gas Works,</i> 2000 Pa. PUC LEXIS 876, Order (Nov. 22, 2000)	273
<i>Pa. PUC v. Phila. Gas Works,</i> Docket No. P-2022-3034264 (Order entered Sep. 21, 2023)	220
<i>Pa. PUC v. Phila. Gas Works,</i> Docket No. R-2023-3037933 (Order entered Nov. 9, 2023)	90, 109
<i>Pa. PUC v. Phila. Suburban Water Co.,</i> 71 Pa. PUC 593 (1989)	11
<i>Pa. PUC v. Philadelphia Suburban Water Company,</i> 1986 Pa. PUC LEXIS 118	72
<i>Pa. PUC v. Roaring Creek Water Co.,</i> 73 Pa. PUC 373 (1990)	37, 116, 200, 287

<i>Pa. PUC v. Total Environmental Solutions, Inc.,</i> Docket Nos. R-00072493 (Order July 30, 2008)	155, 156
<i>Pa. PUC v. Wellsboro Electric Co.,</i> R-2019-3008208 (Order entered Apr. 29, 2020)	90
<i>Pa. PUC v. West Penn Power Co.,</i> 119 PUR4th 110 (Pa. PUC 1990)	116
<i>Proceeding on Motion of the Commission as to the Rates, Charges, Rules</i> <i>and Regulations of Niagra Mohawk Power Corporation d/b/a National</i> <i>Grid for Gas Service,</i> Case No. 24-E-0322, Order (Aug. 14, 2025)	83
<i>Proceeding on Motion of the Commission as to the Rates, Charges, Rules</i> <i>and Regulations of Niagra Mohawk Power Corporation d/b/a National</i> <i>Grid for Gas Service,</i> Case No. 24-G-0323, Order (Aug. 14, 2025)	83
<i>PUC v. Phila. Gas Works,</i> 2023 PA. PUC LEXIS 93, Order (April 20, 2023)	273
<i>Re Limerick Nuclear Generating Station,</i> 1982 Pa. PUC LEXIS 102, Order (May 7, 1982)	78, 79
<i>Re Minnegasco, Inc.,</i> 143 PUR4th 419 (May 3, 1993)	78
<i>Re. Niagra Mohawk Power Co.,</i> 1986 N.Y. PUC LEXIS 3 (Dec. 19, 1986)	77
Statutes	
2 Pa. C.S. § 704	16, 206
6 Pa. C.S. §§ 1504, 1505	273, 289
52 Pa. C.S. § 73.9(c)	65, 66
66 Pa. C.S. 315(a)	65
66 Pa. C.S. § 102	44, 273
66 Pa. C.S. § 315	5, 115
66 Pa.C.S. § 315(a)	<i>passim</i>

66 Pa. C.S. § 315(a), 332(a)	16
66 Pa. C.S. §§ 315(a), 1330	205
66 Pa. C.S. § 315(a), (e)	54, 120
66 Pa. C.S. § 315(c)	274
66 Pa. C.S. § 315(e)	<i>passim</i>
66 Pa. C.S. §§ 315(e), 1353	38, 40, 244
66 Pa. C.S. § 523	273, 289
66 Pa. C.S. § 523(a)	12, 13
66 Pa. C.S. § 526	9
66 Pa. C.S. § 526(a)	13
66 Pa. C.S. § 526(b)	13
66 Pa. C.S. § 1301	<i>passim</i>
66 Pa. C.S. §§ 1301, 1501	12
66 Pa. C.S. § 1301(a)	65
66 Pa. C.S. § 1301.1	52
66 Pa. C.S. § 1304	<i>passim</i>
66 Pa. C.S. § 1316.1	105, 106
66 Pa. C.S. § 1327(d)(1)	254
66 Pa. C.S. § 1330	<i>passim</i>
66 Pa. C.S. § 1330(a)	14, 226, 241
66 Pa. C.S. § 1330(a)(2)	210
66 Pa. C.S. § 1330(b)	14
66 Pa. C.S. §§ 1350-1360	225
66 Pa. C.S. § 1357(a)	229

66 Pa. C.S. § 1357(d)(1).....	218, 254
66 Pa. C.S. § 1402(3).....	287
66 Pa. C.S. § 1404	311
66 Pa. C.S. § 1501	12, 13, 273, 288
66 Pa. C.S. § 1505(a).....	13
66 Pa. C.S. § 1703	64
66 Pa. C.S. § 2202	145
66 Pa. C.S. §§ 2201-2212.....	196
66 Pa. C.S. § 2203(7).....	287
71 P.S. § 309-4	1
71 P.S. § 309-5	17, 272

Regulations

52 Pa. Code § 56.32(e)	308, 310, 311
52 Pa. Code § 69.3301	226
52 Pa. Code § 69.3301-69.3302	206
52 Pa. Code §§ 69.3301, 69.3302(a)	246
52 Pa. Code §§ 69.3301, 3302.....	241, 270
52 Pa. Code § 69.3302(a)	<i>passim</i>
52 Pa. Code § 69.3302(a)(1).....	226
52 Pa. Code § 69.3302(a)(2).....	247
52 Pa. Code § 73.1	65, 81

I. INTRODUCTION

In accordance with the procedural schedule established in this proceeding, before the Honorable Administrative Law Judges (ALJs) Jeffrey A. Watson and Chad Allensworth, of the Office of Administrative Law Judge (OALJ) of the Pennsylvania Public Utility Commission (Commission), the Office of Consumer Advocate (OCA) now submits this Main Brief in opposition to Columbia Gas of Pennsylvania, Inc.'s (Columbia's or Company's) requested rate increase.

The OCA's Tables are attached as Appendix A for the Company's Overall Revenue Requirement (Summary Table). Appendix B provides the OCA's proposed Findings of Fact, Conclusions of Law and Ordering Paragraphs. Appendix C contains a list of the OCA's Testimony and Exhibits that were admitted into the evidence in this case.

A. Description of the Office of Consumer Advocate

The OCA is a statutory advocate with the authority and duty to represent the interest of consumers as a party before the Commission in public utility rate requests.¹ The OCA's interest in this case is to ensure that consumers who ultimately pay the revenue requirement to the Company are paying no more than is necessary to ensure that service remains adequate, reliable, and safe while allowing the Company to have the opportunity to recover its prudently incurred costs and earn a fair rate of return on its investments.

¹ 71 P.S. § 309-4.

B. Procedural History

On March 20, 2025, Columbia Gas of Pennsylvania, Inc. (Columbia or the Company) filed Supplement No. 392 to Tariff Gas Pa. P.U.C. No. 9 with the Commission. The Company proposes to increase rates to produce additional overall revenues of \$110.5 million per year, a 12.0% increase in overall distribution revenue requirement. The Company provides natural gas distribution service to approximately 445,783 residential, commercial, and industrial customers in 26 counties in Central, South-Central, and Southwestern Pennsylvania.

On March 24, 2025, the Commission's Bureau of Investigation & Enforcement (I&E) filed a Notice of Appearance. On April 8, 2025, the OCA filed a Formal Complaint, Public Statement, and Notice of Appearance in this proceeding to protect the interests of consumers in the Company's service territory and to ensure that the Company is permitted to implement only a level of rates that is just and reasonable and in accordance with sound ratemaking principles. On April 11, 2025, the Office of Small Business Advocate (OSBA) filed a Formal Complaint and the Coalition for Affordability and Energy Efficiency in Pennsylvania (CAUSE-PA) filed a Notice of Intervention. On April 24, 2025, the Pennsylvania State University filed a Formal Complaint.

On April 24, 2025, the Commission issued an Order that initiated an investigation into the lawfulness, justness, and reasonableness of the proposed rate increase in this filing in addition to the Company's existing rates, rules, and regulations, assigned this matter to the OALJ for further proceedings as appropriate, and suspended the effective date of the tariff until December 19, 2025.

Approximately 24 consumers have filed formal complaints to date. There were six Public Input Hearings at which nine individuals testified under oath, an overwhelming majority of them in opposition to the Company's rate relief request.² The Public Input Hearings were held as follows:

- On June 3, 2025, at 1:00PM and 6:00PM in Washington, PA.
- On June 4, 2025, at 1:00PM and 6:00PM, telephonically.
- On June 11, 2025, at 1:00PM and 6:00PM in York, PA.

Consistent with the procedural schedule issued by ALJs Watson and Allensworth, the OCA served on the ALJs and the parties its written Direct, Supplemental Direct and Rebuttal, and Surrebuttal Testimonies on June 18, 2025, July 17, 2025, July 31, 2025³, respectively, in which the OCA opposed and/or recommended adjustments to the Company's requests. The testimony served by the OCA in this proceeding was submitted by OCA witnesses Michael Deupree (OCA St. 1, 1SR), Dante Mugrace (OCA St. 2, 2SR), David Garrett (OCA St. 3, 3SR), Jerry Mierzwa (OCA St. 4, 4R, 4SR), Roger Colton (OCA St. 5, 5SR), and Barbara Alexander (OCA St. 6, 6SR).

On August 6, 2025, through August 8, 2025, ALJs Watson and Allensworth held an evidentiary hearing, during which, by stipulation of counsel, the ALJs admitted into the record pre-served testimony and exhibits submitted by witnesses who were not subject to cross-examination as identified by the Company, the Bureau of Investigation and

² Tr. 49-254.

³ Pursuant to the procedural schedule established in the Prehearing Order, the Surrebuttal Testimony of Dante Mugrace, OCA St. 2SR, was served to the parties on August 1, 2025 by 2:00PM. All other surrebuttal testimony submitted by the OCA and other parties was filed by July 31, 2025.

Enforcement (I&E), the OCA, the Office of Small Business Advocate (OSBA), the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania (CAUSE-PA), the Pennsylvania Weather Providers Task Force (PWPTF), and the Pennsylvania State University (PSU). Cross-examination was conducted for Company witnesses Mark Kempic, John Spanos, and John Taylor; I&E witness Esyan Sakaya; and OCA witnesses Dante Mugrace and David Garrett at the hearings on August 6-7, 2025.

On July 29, 2025, the ALJs issued a Briefing Order establishing deadlines for the filing of briefs. In accordance with the Briefing Order, the OCA now submits this Main Brief.

C. Legal Standards

1. Utility Monopoly Regulation

Columbia is a natural gas distribution company with an exclusive monopoly franchise. Customers who reside in its certificated service territory have no choice: if they want natural gas distribution service, they must buy it from Columbia. Utility regulation stems from the state’s police power to protect the health, safety, morals, and general welfare of their citizens. States have the power to regulate the use of private property and the rates charged by certain private companies in industries “clothed with a public interest.”⁴ “[T]he regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States.”⁵ The Public Utility Code governing sales that are only rationally dealt in by a monopoly is a proper exercise of the state police power to regulate

⁴ *Munn v. Illinois*, 94 U.S. 113, 126 (1877).

⁵ *Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm’n*, 461 U.S. 375, 377 (1983).

the health, safety, morals, and general welfare of citizens.⁶ The Commission's comprehensive authority under the Public Utility Code to oversee and regulate jurisdictional public utilities is a constitutional exercise of traditional state police powers as a reasonable exercise of police power by appropriate means for a legitimate end.⁷

2. Burden of Proof

The Company bears the full burden of proof to establish the justness and reasonableness of every element of its requested rate increase:

Reasonableness of rates – In any proceeding upon the motion of the Commission, involving any proposed or existing rate of any public utility, or in any proceedings upon the complaint involving any proposed increase in rates, the burden of proof to show that the rate involved is just and reasonable shall be upon the public utility.⁸

The evidence necessary to meet that burden must be substantial, legally credible, and cannot be a mere “suspicion” or “scintilla” of evidence.⁹

The party with the burden of proof has a formidable task to show that the Commission may lawfully adopt its position.¹⁰ Even where a party has established a prima

⁶ *Relief Elec. Light, Heat & Power Co's. Petition*, 63 Pa. Super 1, 6-11, 1916 Pa. Super. LEXIS 89 (Pa. Super. 1916).

⁷ *Jenkins Twp. v. Pub. Serv. Comm'n*, 65 Pa. Super. 122, 1916 Pa. Super. LEXIS 30, **15-16 (Pa. Super. 1916) (“The authority which the commission seeks to exercise in this case is clearly the exercise of the police power inherent in our State as delegated to the commission by the provisions of the Public Service Company Law” (which the Public Utility Law of 1937 replaced) (which the Code (of 1978) replaced)); *see also* Charles F. Phillips, Jr., *The Regulation of Public Utilities: Theory and Practice*, 87 (Pub. Utils. Reports, Inc., 3rd ed. 1993); James H. Booser, *The Constitutional Limitations on Public Utility Regulation*, 67 Dick. L. Rev. 363, 364 (1963), *available at*: <https://ideas.dickinsonlaw.psu.edu/dlra/vol67/iss4/3> (last visited Mar. 21, 2024).

⁸ 66 Pa. C.S. § 315(a).

⁹ *Lower Frederick Twp. Water Co. v. Pa. PUC*, 409 A.2d 505, 507 (Pa. Cmwlth. Ct. 1980); *Lansberry v. Pa. PUC*, 578 A.2d 600, 602 (Pa. Cmwlth. Ct. 1990) (*Lansberry*).

¹⁰ *Burleson v. Pa. PUC*, 461 A.2d 1234, 1236 (Pa. 1983) (*Burleson*).

facie case, the party with the burden must establish that “the elements of that cause of action are proven with substantial evidence which enables the party asserting the cause of action to prevail, precluding all reasonable inferences to the contrary.”¹¹ Furthermore, it is well-established that the “degree of proof before administrative tribunals as well as before most civil proceedings is satisfied by establishing a preponderance of the evidence.”¹²

The burden of proof does not shift to parties challenging the rate increase, but rather must be met by the utility:

It is well-established that in general rate increase proceedings, the burden of proof does not shift to parties challenging a requested rate increase. Rather, the utility’s burden of establishing the justness and reasonableness of every component of its rate request is an affirmative one and that burden remains with the public utility throughout the course of the rate proceeding. It has been held that there is no similar burden placed on other parties to justify a proposed adjustment to the utility’s filing.¹³

In *Berner*, the Pennsylvania Supreme Court stated:

[T]he appellants did not have the burden of proving that the plant additions were improper, unnecessary or too costly; on the contrary, that burden is, by statute, on the utility to demonstrate the reasonable necessity and cost of the installations and that is the burden which the utility patently failed to carry.¹⁴

The Commission recognizes in its rate determinations that the burden of proof will not shift to a complainant or intervener that is challenging the requested rate increase.¹⁵ Thus, it is

¹¹ *Id.*

¹² *Lansberry*, 578 A.2d at 602.

¹³ *Pa. PUC v. Pa.-American Water Co.*, 231 P.U.R.4th 277, 2004 Pa. PUC LEXIS 29, *16-18 (Jan. 29, 2004) (*PAWC 2004*) (citing *Berner v. Pa. PUC*, 116 A.2d 738 (Pa. 1955) (*Berner*)).

¹⁴ *Berner*, 116 A.2d at 744.

¹⁵ *Pa. PUC v. Equitable Gas Co.*, 57 Pa. PUC 423, 471 (1983); see also *University of Pa. v. Pa. PUC*, 485 A.2d 1217 (Pa. Cmwlth. Ct. 1984); *Pa. PUC v. PPL Elec. Utils. Corp.*, 237 PUR4th 419 (PaPUC 2004) (Order entered Dec. 22, 2004).

unnecessary for the OCA (or any challenger) to prove that the Company's proposed rates – including its proposed alternative ratemaking mechanism – are unjust, unreasonable, or not in the public interest. To prevail in its challenge, Pennsylvania law requires only that the OCA show *how* the Company failed to meet its burden of proof. While subtle, this critical distinction shows that parties opposing a utility in a rate proceeding need only to shift the burden of going forward to prevail.

A public utility may elect to use a future test year (FTY) or a fully projected future test year (FPFTY) “in discharging its burden of proof.”¹⁶ However, the utility must provide evidence to support all estimates of increased costs in its FTY and FPFTY. The Code provides:

Whenever a utility utilizes a future test year or a fully projected future test year in any rate proceeding and such future test year or a fully projected test year forms a substantive basis for the final rate determination of the commission, *the utility shall provide*, as specified by the commission in its final order, *appropriate data evidencing the accuracy of the estimates contained in the future test year or a fully projected future test year*, and the commission may after reasonable notice and hearing, in its discretion, adjust the utility's rates on the basis of such data.¹⁷

Should the utility fail to prove that the projections relied upon in its FTY or FPFTY are accurate, the Commission should not accept those projections and may adjust the public utility's revenue requirement increase request to remove unsupported projections.¹⁸

¹⁶ 66 Pa. C.S. § 315(e).

¹⁷ *Id.* (emphasis added).

¹⁸ *Id.*

3. Just and Reasonable and Not Unduly Discriminatory Rates

As a matter of law, a public utility's rates must be just and reasonable and in conformity with regulations or orders of the Commission.¹⁹ A public utility may obtain "a rate that allows it to recover those expenses that are reasonably necessary to provide service to its customers[,] as well as a reasonable rate of return on its investment."²⁰

The Commission "has broad discretion in determining whether rates are reasonable" and "is vested with discretion to decide what factors it will consider in setting or evaluating a utility's rates."²¹ The Commission's discretion to determine if a requested rate is just and reasonable includes the "power to make and apply policy" concerning the appropriate balance between rates charged to consumers and returns allowed to utility investors.²²

There is ample authority for the proposition that the power to fix "just and reasonable" rates imports a flexibility in the exercise of a complicated regulatory function by a specialized decision-making body and that the term "just and reasonable" *was not intended to confine the ambit of regulatory discretion to an absolute or mathematical formulation but rather to confer upon the regulatory body the power to make and apply policy* concerning the appropriate balance between prices charged to utility customers and returns on capital to utility investors consonant with constitutional protections applicable to both.²³

¹⁹ 66 Pa. C.S. § 1301(a).

²⁰ *City of Lancaster Sewer Fund v. Pa. PUC*, 793 A.2d 978, 982 (Pa. Cmwlth. 2002) (*Lancaster 2002*).

²¹ *Popowsky v. Pa. PUC*, 683 A.2d 958, 961 (Pa. Cmwlth. Ct. 1996) (*Popowsky 1996*) (emphasis added).

²² *Popowsky v. Pa. PUC*, 665 A.2d 808, 812 (Pa. 1995) (*Popowsky 1995*).

²³ *Id.* (citations omitted) (emphasis added).

A utility's cost of providing service guides the ratemaking process.²⁴ Additional important ratemaking concerns include quality of service, rate gradualism, and rate affordability.²⁵

The Commission must determine whether projected expenses “are reasonably necessary to provide service...” during the prospective period in which its rates will be in effect.²⁶ Only prudently incurred expenses are includable in expense claims; it is the burden of the public utility to prove that the expenses incurred are just and reasonable; and it is within the discretion of the Commission to exclude expenses as unreasonable.²⁷

Additionally, rates must not be unduly discriminatory among customer groups.²⁸ The Commission has discretion to determine reasonable classification of service of rates as may be justified “by a variety of considerations including the quantity of service used, the nature of the use, the time of the use, the pattern of the use, differences of conditions of service or cost of service.”²⁹

²⁴ *Lloyd v. Pa. PUC*, 904 A.2d 1010, 1019-21 (Pa. Cmwlth. 2006) (*Lloyd*).

²⁵ *Pa. PUC v. Columbia Gas of Pa., Inc.*, Docket No. R-2020-3018835 (Order Feb. 19, 2021) (*Columbia 2021*), at 46-47 (citing 66 Pa. C.S. §§ 523, 526(a)) (citing also *Lloyd* at 1020 and *Pa. PUC v. Twin Lakes Util., Inc.*, Docket No. R-2019-3010958 (Order Mar. 26, 2020) at 48, 80) (available at <https://www.puc.pa.gov/pcdocs/1693880.docx>).

²⁶ *Lancaster 2002*, 793 A.2d at 982.

²⁷ *Popowsky v. Pa. PUC*, 674 A.2d 1149, 1154 (Pa. Cmwlth. 1996) (*LP Water*) (internal citations omitted).

²⁸ 66 Pa. C.S. § 1304.

²⁹ *Zucker v. Pa. PUC*, 402 A.2d 1377, 1382 (Pa. Cmwlth. 1979) (*Zucker*).

4. Reasonable Opportunity to Earn a Fair Rate of Return

A public utility is entitled to no more than a reasonable opportunity to earn a fair rate of return on its investments dedicated to public service.³⁰ The United States Supreme Court held:

The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to raise the money necessary for the proper discharge of public duties.³¹

The allowed rate of return should reflect:

[A] return on the value of the [utility's] property which it employs for the convenience of the public equal to that being made at the same time on investments in other business undertakings which are attended by corresponding risks and uncertainties.³²

However, a fair return for public utility service is not equivalent to “profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.”³³ A fair rate of return “should be commensurate with returns on investments in other enterprises having corresponding risks” while being sufficient “to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.”³⁴ The Supreme Court noted, however, that:

The rate-making process under the Act, i.e., the fixing of ‘just and reasonable’ rates, involves a balancing of the investor and consumer

³⁰ *Pennsylvania Gas & Water Co. v. Pa. PUC*, 341 A.2d 239, 251 (Pa. Cmwlth. 1975) (citations omitted).

³¹ *Bluefield Water Works and Improvement Co. v. Public Serv. Comm’n of W.Va.*, 262 U.S. 679, 692-93 (1923) (*Bluefield*).

³² *Bluefield*, 262 U.S. at 692.

³³ *Id.* at 692-693.

³⁴ *Federal Power Comm’n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (*Hope*).

interests. Thus we stated...that *regulation does not insure that the business shall produce **net** revenues.*”³⁵

Consumers cannot readily negotiate with a utility and must “rely upon” the Commission to provide “a complete, permanent, and effective bond of protection from excessive rates and charges” of the public utility.³⁶ The Commission’s “responsibilities include the protection of future, as well as present, consumer interests.”³⁷ Rates adopted by the Commission that are within a “zone of reasonableness” can withstand constitutional scrutiny.³⁸

Cost of capital analyses are generally accepted by the Commission as a basis for determining a fair rate of return under the “just and reasonable” standard of the Code. In *PSW 1989*, the Commission defined an appropriate rate of return as:

[T]he amount of money a utility earns, over and above operating expenses, depreciation expense, and taxes, expressed as a percentage of the legally established net valuation of utility property, the rate base. Included in the “return” are interest on long-term debt, dividends on preferred stock, and earnings on common equity. In other words, the return is the money earned from operations which is available for distribution among the various classes of contributors of money capital.³⁹

Additionally, the Commission stated:

³⁵ *Id.* (emphasis added) (internal quotations omitted); see also *Pa. PUC v. Phila. Suburban Water Co.*, 71 Pa. PUC 593, 623 (1989) (*PSW 1989*) (citing *Pittsburgh v. Pa. PUC*, 69 A.2d 844 (Pa. Super Ct. 1949)); see also *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 310, 312 (1989) (*Duquesne Light*), *aff’g Barasch v. Pa. PUC*, 532 A.2d 325 (Pa. 1987).

³⁶ *Permian Basin Area Rate Cases*, 390 U.S. 747, 794-95 (1968) (*Permian Basin*) (citing *Atlantic Ref. Co. v. Pub. Serv. Comm’n*, 360 U.S. 378, 388 (1981)).

³⁷ *Permian Basin*, 390 U.S. at 797.

³⁸ *Id.* at 797.

³⁹ *PSW 1989* at 622-23 (quoting Paul J. Garfield & Wallace F. Lovejoy, *Public Utility Economics*, 116 (1964)).

A fair rate of return for a public utility, however, is not a matter which is to be determined by the application of a mathematical formula. It requires the exercise of informed judgment based upon an evaluation of the particular facts presented in each proceeding. There is no one precise answer to the question as to what constitutes the proper rate of return. The interests of the Company and its investors are to be considered along with those of the customers, *all to the end of assuring adequate service to the public at the least cost*, while at the same time maintaining the financial integrity of the utility.⁴⁰

5. Adequate Quality of Service to Be Observed

Under Section 1501 of the Public Utility Code:

Every public utility shall furnish and maintain adequate, efficient, safe, and reasonable service and facilities, and shall make all such repairs, changes, alterations, substitutions, extensions, and improvements in or to such service and facilities as shall be necessary or proper for the accommodation, convenience, and safety of its patrons, employees, and the public. Such service also shall be reasonably continuous and without unreasonable interruptions or delay.⁴¹

If a utility is not providing adequate, efficient, safe, and reasonable service, then the rates that it charges for that service are not just and reasonable.⁴² During the course of a Section 1308(d) general rate increase request, the Commission “shall consider, in addition to all other relevant evidence of record, the efficiency, effectiveness and adequacy of service of each utility when determining just and reasonable rates.”⁴³ If a utility’s service is found to be inadequate, then the Commission “shall give effect to this section by making such

⁴⁰ *Pa. PUC v. Pa. Power Co.*, 55 Pa. PUC 552, 579 (1982) (*Pa. Power*) (emphasis added); see also *Pa. PUC v. Nat’l Fuel Gas Dist. Corp.*, 73 Pa. PUC 552, 603-05 (1990) (*NFGD 1990*).

⁴¹ 66 Pa. C.S. § 1501.

⁴² 66 Pa. C.S. §§ 1301, 1501; see *Nat’l Utils. v. Pa. PUC*, 709 A.2d 972, 973 (Pa. Cmwlth. 1998) (holding that whether rates are just and reasonable is inextricably intertwined with the quality of service provided).

⁴³ 66 Pa. C.S. § 523(a).

adjustments to specific components of the utility's claimed cost of service as it may determine to be proper and appropriate” as supported by the evidence in the proceeding.⁴⁴ The Commission may deny a requested rate increase, in whole or in part, if the Commission determines that the service provided by the utility is inadequate.⁴⁵

In a matter set for hearings, including a Section 1308(d) rate proceeding, the Commission is empowered to make findings as to the adequacy, safety, sufficiency, and reasonableness of the service provided by a public utility.⁴⁶ Should the Commission determine that the utility service being provided by the public utility does not meet the statutory requirements of Section 1501 during the course of a Section 1308(d) general rate increase request, then the Commission:

shall determine and prescribe, by regulation or order, the reasonable, safe, adequate, sufficient, service or facilities to be observed, furnished, enforced, or employed, including all such repairs, changes, alterations, extensions, substitutions, or improvements in facilities as shall be reasonably necessary and proper for the safety, accommodation, and convenience of the public.⁴⁷

The Public Utility Code does not provide that the cost of service adjustments available to the Commission under Sections 523(a) and 526(a) are mutually exclusive with the Commission’s ability to determine and prescribe the quality of service to be observed by a public utility.⁴⁸ Rather, if consumers are receiving inadequate service, then the sufficient

⁴⁴ *Id.*

⁴⁵ 66 Pa. C.S. § 526(a).

⁴⁶ 66 Pa. C.S. § 1505(a).

⁴⁷ 66 Pa. C.S. § 1505(a).

⁴⁸ 66 Pa. C.S. § 526(b).

relief to be afforded is both reducing the cost of service as well as ensuring that the utility begins to provide adequate service by prescription of the quality of service to be observed.

6. Alternative Ratemaking Mechanisms

Under Section 1330 of the Public Utility Code, the General Assembly authorized the Commission to permit the implementation of alternative rate mechanisms notwithstanding other provisions of law.⁴⁹ In its declaration of policy, the General Assembly identified that the purpose of alternative rate mechanisms is to (1) create new opportunities for customers through innovations in utility operations and information technologies and (2) encourage and sustain investment through cost-recovery mechanisms enhancing safety and reliability of infrastructure “consistent with the efficient consumption of utility service.”⁵⁰ Among the permitted forms of alternative rate mechanisms, the General Assembly identified decoupling mechanisms, performance-based rates, formula rates, and multiyear rate plans as the type of mechanisms for the Commission to consider.⁵¹

Following the General Assembly’s enactment of Section 1330, the Commission issued a policy statement regarding the factors that it will consider when assessing alternative rate mechanisms.⁵² In the Policy Statement, the Commission specifically identified 14 factors to consider, which are:

⁴⁹ 66 Pa. C.S. § 1330.

⁵⁰ 66 Pa. C.S. § 1330(a).

⁵¹ 66 Pa. C.S. § 1330(b).

⁵² *Fixed Service Utilities Distribution Rates Policy Statement*, Docket No. M-2015-2518883 (Order entered July 18, 2019) (available at: <https://www.puc.pa.gov/pcdocs/1627831.docx>).

- (1) How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.
- (2) How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.
- (3) Whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.
- (4) How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.
- (5) How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.
- (6) How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.
- (7) How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs.
- (8) How the ratemaking mechanism and rate design impact customer rate stability principles.
- (9) How weather impacts utility revenue under the ratemaking mechanism and rate design.
- (10) How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.
- (11) If or how the ratemaking mechanism and rate design interact with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa.C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa.C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa.C.S. § 1353 (relating to distribution system improvement charge).
- (12) Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.
- (13) Whether the alternative ratemaking mechanism and rate design are understandable to consumers.

(14) How the ratemaking mechanism and rate design will support improvements in utility reliability.⁵³

While no one factor is dispositive, the Commission may consider these factors when determining whether the alternative rate mechanism proposed is just and reasonable.⁵⁴ The Commission may also consider other relevant factors if necessary.

Notably, neither Section 1330 nor the Commission's policy factors affect the requirements of the Public Utility Code discussed *supra*. Rates must still be just and reasonable under the proposed alternative rate mechanism.⁵⁵ The utility is still required to satisfy its burden of proof that the proposed alternative rate mechanism will result in just and reasonable rates.⁵⁶ The Commission's decision must be based on substantial evidence found in the record before it and not in the consideration of other rate mechanisms approved in Pennsylvania or neighboring jurisdictions.⁵⁷ The adoption of a similar alternative rate mechanism by a utility pursuant to a settlement agreement should not be considered to be evidence or precedential for purposes of assessing the alternative rate mechanism placed before the Commission.⁵⁸

⁵³ 52 Pa. Code § 69.3302(a).

⁵⁴ *Id.*

⁵⁵ 66 Pa. C.S. § 1301.

⁵⁶ 66 Pa. C.S. § 315(a), 332(a).

⁵⁷ 2 Pa. C.S. § 704.

⁵⁸ *HIKO Energy, LLC v. Pa. PUC*, 163 A.3d 1079, 1102-03 (Pa. Cmwlth. 2017) *aff'd by HIKO Energy, LLC v. Pa. PUC*, 209 A.3d 246, 255 (Pa. 2019) (settlement agreements are not precedential); *Bell Atl. – Pa., Inc. v. Pa. PUC*, 672 A.2d 352, 354 (Pa. Cmwlth. 1995) (administrative agencies are not bound by the rule of *stare decisis*, but must render consistent opinions that affirm, overrule, or distinguish prior opinions).

7. Due Consideration to the Interest of Consumers

As a matter of law, an increase in base rates involves a substantial property right, entitling ratepayers to notice and procedural due process.⁵⁹ Given that a utility's general rate increase request will substantially affect the interests of consumers, the Commission must "consistent with its other statutory responsibilities, take such action with due consideration to the interests of consumers."⁶⁰

D. Statement of the Case

1. Overview of the Filing

The OCA conducted a thorough investigation into Columbia's request for an increase in annual operating revenues of \$110.5 million, or approximately 12.0%. This increase would be paid-for by more than 445,000 residential, commercial, and industrial customers in portions of 26 counties throughout Central, South-Central, and Southwestern Pennsylvania. In this case, Columbia used a Historic Test Year (HTY) ending November 30, 2024, a Future Test Year (FTY) ending November 30, 2025, and a Fully Projected Future Test Year (FPFTY) ending December 31, 2026.

If the Company's requested rate increase were granted as proposed, the monthly bill for a residential customer using 70 therms would increase from \$138.52 to \$154.29, an increase of \$15.77 or 11.4%. This increase includes a proposal to raise the residential customer charge – the amount that a residential customer must pay on their monthly bill

⁵⁹ *McCloskey v. Pa. PUC*, 195 A.3d 1055, 1068 (Pa. Cmwlth. Ct. 2018) (*McCloskey 2018*) (citing *Barasch v. Pa. PUC*, 546 A.2d 1296, 1305-06 (Pa. Cmwlth. Ct. 1988) (*Barasch 1988*); citing also U.S. Const. amend. XIV, § 1).

⁶⁰ 71 P.S. § 309-5.

regardless of usage – from \$17.25 to \$31.97, an increase of \$17.72 or 85.3%. Columbia currently charges the highest residential customer charge in the Commonwealth and, under its proposed increase, the residential customer charge would be nearly double the next-highest residential customer charge of \$16.25.⁶¹ Of the Company’s overall rate increase request, approximately 66.9% will come from residential customers.⁶²

2. Summary of Public Input Hearing Testimony

The OCA includes a comprehensive summary of the Public Input Hearing testimony submitted in this case in OCA Exh. RDC-3. The following summary emphasizes the issues of primary concern for Columbia’s ratepayers.

Affordability Concerns

Multiple Columbia customers testified that they are struggling to pay their current Columbia bills and are worried about the effect that the proposed increase will have on their communities, especially during a time of high inflation affecting household expenses like rent and grocery prices.

As stated by Ms. Evans, “heating is becoming a luxury.”⁶³ Ms. Evans “feel[s] that Columbia Gas should have to roll back rates, not increase rates, because heating is a necessity and people need to be able to afford it.”⁶⁴ Ms. Evans stated that she keeps her “thermostat at 62 all winter long,” meaning that she is “quite cold.”⁶⁵ In recent years, she

⁶¹ OCA St. 4 at 15.

⁶² *Id.* at 9.

⁶³ Tr. 217.

⁶⁴ Tr. 219.

⁶⁵ Tr. 216.

kept her “thermostat at 69 and didn’t have bills that approach over \$600.”⁶⁶⁶⁷ As a self-described senior, Ms. Evans testified that “in the winter, [she] freezes.”⁶⁸

Columbia’s customers also identified that the proposed rate increase may adversely affect low-income customers and senior citizens on fixed incomes who do not qualify for universal services programs. Mr. Story, on behalf of the Center for Coalfield Justice (CCJ), stated that the “CCJ is concerned by Columbia’s continued effort to shift the financial burden of infrastructure investments and corporate profits onto ratepayers, particularly low and fixed income households in southwestern Pennsylvania.”⁶⁹ According to Mr. Story, “the continued rate escalation [by Columbia] is not sustainable for many of the households CCJ represents and disproportionately affects vulnerable ratepayers.”⁷⁰ As identified by Mr. Story, “[l]imited assistance programs do not justify a systematic rate hike that will harm thousands of households not enrolled in such programs.”⁷¹

Ms. Evans testified that “it will be even worse when I’m on a fixed income as so many people in this state are, and surely in Columbia’s service area. And it just seems like no one considers the ability of peoples to afford these increase.”⁷² Ms. Evans expressed concern that “if you’re really poor, there’s programs to assist you, but if you exceed income guidelines, there aren’t. And so you take steps like I did, lowering your thermostat to

⁶⁶ Tr. 216.

⁶⁷ Tr. 217.

⁶⁸ Tr. 217.

⁶⁹ Tr. 179.

⁷⁰ Tr. 180.

⁷¹ Tr. 182.

⁷² Tr. 217.

unhealthy levels so that you can pay the bill. So I am 70-years-old now and I am still working.”⁷³

Ms. Brown testified that the budget for her budget billing plan has increased substantially over the course of the past year, from “a budget of \$170 monthly” on her “December 19th bill, 2024,” “on the January bill, the budget went up to \$181...And it continued until [she] got [her] May bill,” on which “the budget increased to 219 a month. And when you look back to December to now, that is an increase of over 20 percent.”⁷⁴ She stated that it is “getting harder and harder each month to pay some of these bills because [her] fixed income certainly hasn’t gone up that much.”⁷⁵ She thinks “that Columbia Gas needs to consider each customer and consider how hard it is getting for customers to continue this upward trend of these gas bills.”⁷⁶ Ms. Brown expressed concern that the income guidelines for Columbia’s universal service programs “don’t seem to raise in accordance to what our gas bills are raising. So I, you know, I don’t get any assistance that way either.”⁷⁷

The public input hearing testimony also identified concerns from the Company’s customers about the affect of the proposed increase on their communities due to current economic conditions. Ms. Evans feels like she is “going to be forced to move to a warmer climate because [she] can’t afford to heat the house here.” Mr. Story requested that the

⁷³ Tr. 217.

⁷⁴ Tr. 225-26.

⁷⁵ Tr. 227.

⁷⁶ Tr. 227.

⁷⁷ Tr. 228.

Commission should “consider the long-term economic impacts on residential ratepayers, particularly those already struggling with high utility costs. Rate designs should prioritize affordability, encourage conservation, and distribute costs equitably, goals that Columbia’s proposal fails to meet.”⁷⁸

Mr. Louderback testified that Columbia’s proposal “is not merely a minor change, but it’s a substantial financial burden for residents and businesses across the service territory, especially amidst the current economic uncertainty and rising costs.”⁷⁹ He further stated:

In a time when Pennsylvania businesses and households face an increasingly complex economic landscape marked by tariffs, rising operational costs, labor shortages, and general economic uncertainty over inflation and interest rates, and with the cost of Pennsylvanians already experiencing a two percent higher quality and standard of living than the national average, including a six percent higher utility cost than the national average, it is crucial that utility services remain affordable.⁸⁰

Ms. Dunlap stated that “with the way inflation is, grocery prices, mortgage, rent, et cetera, a lot of people are struggling and can’t understand why this rate increase is being proposed.”⁸¹ She expressed concern whether Columbia’s universal service programs are “enough for low-income people? Is there a balance? Low-income people need the help. People are still struggling to pay their bills. And at the same time this company is asking for rate increase [sic] that is extremely high.”⁸²

⁷⁸ Tr. 182-83.

⁷⁹ Tr. 187.

⁸⁰ Tr. 189-90.

⁸¹ Tr. 138.

⁸² Tr. 140.

Customer Charge

Several of the customers who testified at the public input hearings specifically objected to Columbia's proposal to dramatically increase its residential customer charge.

Mr. Story expressed concern regarding "Columbia's proposal to increase the fixed monthly residential customer charge by 85 percent from \$17.25 to \$31.97," stating that "[f]ixed charges are inherently regressive. They do not vary with usage, and therefore penalize ratepayers who attempt to reduce consumption through conservation, efficiency, or economic necessity."⁸³ He testified that the customer charge proposal "undermines households' ability to manage utility costs and disproportionately impacts those least able to afford higher bills."⁸⁴

Mr. Louderback also identified that the customer charge is an area of primary concern for him. He described the proposed increase as:

[A] deeply regressive charge that disproportionately burdens our most vulnerable neighbors. Seniors on fixed incomes...low income families, and those like me who diligently work every day to conserve as much energy as possible. They will face a significant, unavoidable cost increase regardless of their efforts to keep their bill down.⁸⁵

Energy Efficiency and Conservation

Columbia's customers also described the breakdown of their monthly natural gas bills, expressing concern that the commodity cost of natural gas is a relatively small overall

⁸³ Tr. 180.

⁸⁴ Tr. 180.

⁸⁵ Tr. 187.

portion of their total bill, with distribution charges occupying a significant portion of their overall bill.

Mr. Story testified:

[T]he overall structure of the proposed rate changes include higher fixed charges and normalization adjustments, undermines the economic incentives for ratepayers to conserve energy. When customers cannot reduce their bills by using less gas, they lose motivation to engage with efficiency programs, which contradicts both public policy and environmental goals.⁸⁶

Ms. Evans testified that, for her two highest bills from this most recent winter, which were only for heating, “the cost of gas was \$99, but the cost of distribution was over \$400. And so the total bill was \$668.90. And then on the other February bill, the amount was \$91.16 for the gas, but the distribution cost was \$382.29 with a total bill of \$654.52.”⁸⁷ Based on these figures, she stated that “it’s obvious how much of the gas bill, how high is the cost of distribution from Columbia Gas.”⁸⁸

According to Mr. Skvarla, his “supply charge for last month was \$7, but [his] bill was \$67. The rest is all delivery charges.”⁸⁹

Ms. Brown identified that on her “February bill, the detailed charges, the delivery charges, it was \$415.75. Gas usage, so what [she] actually paid for gas was \$57.”⁹⁰

Ms. Garlitz testified that “I have nothing to say about the actual gas used. It’s the distribution. My gas bill, in January, I used \$132 worth of gas. My bill was \$861. That’s

⁸⁶ Tr. 182.

⁸⁷ Tr. 216; Evans Exh. 1.

⁸⁸ Tr. 216.

⁸⁹ Tr. 169.

⁹⁰ Tr. 226.

652 percent more than the gas I'm paying for. That's absurd. Nobody should be paying that.”⁹¹

Frequency of Rate Cases

Columbia's customers also expressed frustration with the number of rate increase requests filed by Columbia in recent years.

Mr. Skvarla testified that Columbia customers “went through this last year...and maybe the year before.”⁹² He expressed concern regarding how many times Columbia “is going to keep back asking for \$100 million here and \$100 million there?”⁹³

Mr. Story identified that “[i]f approved, this would be Columbia's 12th distribution rate increase in the past 15 years, establishing a troublesome pattern of imposing reoccurring financial burdens on consumers.”⁹⁴ Mr. Story questioned the need for Columbia's requested rate increase, stating that “Columbia has not shown that it needs such a significant rate increase. It is not explained why existing revenue or smaller increases would not be enough to cover these costs.”⁹⁵

Mr. Louderback expressed concern that Columbia's distribution rates were already “changed less than a year ago, with new rates taking place on December 14th of last year. To propose another rate increase soon after a recent adjustment is an unacceptable burden.”⁹⁶

⁹¹ Tr. 66.

⁹² Tr. 168.

⁹³ Tr. 168.

⁹⁴ Tr. 179.

⁹⁵ Tr. 179.

⁹⁶ Tr. 189.

Ms. Evans testified “that until 2022, they received two increases that year that together totaled nearly 25%. And [she] believe[s] that in January of this year they received an increase of around nine percent.”⁹⁷ She understands “that Columbia Gas needs to make improvements and – but their increases to me are frequent. They are high, and they far exceed the cost of inflation.”⁹⁸

Weather Normalization Adjustment and Revenue Normalization Adjustment

Columbia’s customers who testified regarding the proposed WNA and RNA objected to Columbia’s requests to implement them. Regarding the proposed WNA, several customers discussed their experience with the one-directional bill adjustments experienced under the WNA Pilot.

Mr. Skvarla requested that the proposed WNA and RNA be denied.⁹⁹ Specifically, Mr. Skvarla stated that he is opposed to the WNA because “it’s a charge based on nothing. If it’s warmer outside, how can I control the weather” If it’s warmer outside and I use less gas, my bill should be less. You shouldn’t charge me for something because the weather is warmer outside.”¹⁰⁰ Regarding the proposed RNA, Mr. Skvarla asked “who normalizes my revenue? How do you get revenue normalization? ... Where can I make up something where I get revenue normalization?”¹⁰¹

⁹⁷ Tr. 215-16.

⁹⁸ Tr. 217.

⁹⁹ Tr. 169.

¹⁰⁰ Tr. 172.

¹⁰¹ Tr. 173.

Mr. Story also expressed concern regarding the proposed WNA and RNA. As stated by Mr. Story

These mechanisms protect Columbia's revenue stream due to decreased consumption, effectively shifting the risk of weather and usage variability away from the utility and onto ratepayers. Such measures are inconsistent with equitable rate design and send a problematic signal. Ratepayers will pay more regardless of usage while Columbia's profit margins [] remain protected. The introduction of new rate classes and pilot programs must not come at the expense of affordability.¹⁰²

Ms. Evans testified that, about the WNA:

If you read on the Columbia Gas's own website about weather normalization, it tells you that over time your bill should total the same as it would without applying weather normalization, which simply provides a more even method of collecting delivery costs. But that is really not so.¹⁰³

Ms. Evans "made a list of how much [she] was charged in a weather normalization charge over those months, with the lowest being in April of 2024 for \$3.64 and the highest being in February of 2024 for \$81.05. But all of them totaled \$234.96" during the WNA Pilot's effective period "from November 2023 through May 2024."¹⁰⁴ During the 2024-2025 heating season, Ms. Evans did not total the amount, but "for every month except for once, [she] was again charged a weather normalization charge. [She] received one month of a credit of three dollars and some cents."¹⁰⁵ According to Ms. Evans:

[T]he reality of weather normalization is that it does not even out over time. You get charged every month because the climate has been getting warmer.

¹⁰² Tr. 181.

¹⁰³ Tr. 218.

¹⁰⁴ Tr. 218.

¹⁰⁵ Tr. 218-19.

As so you're always hit with a weather normalization charge and it does not even out over time. You don't see the credits coming back.”¹⁰⁶

Ms. Schlag testified that “[i]t is totally unfair to charge people for services, products that they don't receive and did not request.”¹⁰⁷ She further stated that “it doesn't make sense that as I try to be very careful of how much I consumer, that the gas company is charging me for what I don't consume.”¹⁰⁸ Ms. Schlag testified:

[Columbia] should be smart enough to understand climate change, understand their process of billing so that they don't suffer the consequences that apparently they have been suffering. But I should in no way pay for the inability or the refusal of Columbia Gas to solve their problem. There is no benefit to the customers. None at all.¹⁰⁹

Mr. Louderback also testified in opposition to the WNA.¹¹⁰

II. SUMMARY OF ARGUMENT

Overall Position

Columbia already charges the highest rates to residential customers in Pennsylvania, and the third-highest rates in the mid-Atlantic. The Company has filed for a general rate increase request five times in the last six years and has significantly increased its revenues per customer despite declining usage per customer. Yet, Columbia's predominant concern in this rate case is its revenue stability. As part of this proceeding, Columbia has requested a significant increase in its residential customer charge, a permanent Weather Normalization Adjustment, and a Revenue Normalization Adjustment without providing

¹⁰⁶ Tr. 219.

¹⁰⁷ Tr. 233.

¹⁰⁸ Tr. 233.

¹⁰⁹ Tr. 234.

¹¹⁰ Tr. 187-88.

customers with benefits from its decreased revenue risk such as a lower return on equity claim, meeting minimum performance objectives, or reducing the frequency of its rate filings. Instead, Columbia proposes to maintain the *status quo* while extracting additional revenues from its captive customers. Due to the threat posed by the Company's requested rate increase and alternative rate mechanisms to Columbia's customers' long-term affordability and energy efficiency incentives, the OCA requests that the Commission adopt its recommendations set forth in full below.

Revenue Requirement

The OCA recommends that the Commission authorize a revenue requirement decrease of no less than \$36,316,933, or \$146,813,730 lower than the Company's requested revenue requirement increase of \$110,496,797.

The OCA's recommended revenue requirement decrease is based on a number of adjustments proposed by OCA witnesses Mugrace and Garrett to the Company's claimed rate base balance, expenses, and income tax expense. The OCA's recommendations regarding depreciation expense and rate of return are summarized separately below. Columbia requested the inclusion of costs in its rate base and expense balances associated with inflationary adjustments that are not known and measurable. Rather, they are merely estimates that are not sufficient to meet Columbia's burden of proof. Further, the Company requests recovery of costs which do not directly benefit ratepayers but instead operate to the benefit of the Company and its shareholders, which the Commission is empowered to disallow. The OCA recommends that these costs be disallowed for ratemaking purposes because they are not consistent with the requirements of the Public Utility Code,

Commission precedent, and/or the public interest and operate only to unnecessarily inflate the amount included in rates.

Depreciation Expense

The issue in this case is about the Company's proposed recovery of excessive amounts charged to operating expenses for annual depreciation that would lead to consumers paying unjust and unreasonable rates to the tune of \$63.615 million per year. The OCA carried its burden of production to show that use of the Average Life Group (ALG) procedure over the Company's claimed Equal Life Group (ELG) procedure will produce just and reasonable rates. Adopting the ALG procedure is squarely within the Commission's ratemaking discretion, as no state or federal law prohibits the Commission's adoption of the ALG procedure in this proceeding. Substantial record evidence demonstrates that the use of the ALG procedure will permit the Company's recovery of reasonable amounts charged to operating expenses for depreciation so that the Company is whole and the integrity of its investments maintained. Substantial record evidence further demonstrates that use of the ALG procedure will allow the Company's accumulated depreciation and annual depreciation to be calculated on a reasonably consistent basis. However, use of the ALG procedure would mean that the excess amounts charged in rates for depreciation expense will be removed. Furthermore, substantial record evidence demonstrates that the use of the ELG procedure unreasonably accelerates the recovery of depreciation expense, is inconsistent with the well-established "matching" ratemaking principle, and creates intergenerational inequity among consumers paying utility rates.

Moreover, a significant majority of state commissions approve the ALG procedure, leaving Pennsylvania in the small minority of jurisdictions that approve the ELG procedure.

Rate of Return

The OCA recommends that the Commission adopt a market-based weighted cost of capital of 7.06%, including a capital structure for ratemaking purposes of 50% common equity and 50% debt, and a return on equity of 8.9%. The Company's requested capital structure includes an equity component which is significantly greater than the percentage of equity capital maintained by the members of the proxy group used to calculate the cost of equity. Further, Columbia's requested return on equity of 11.35% is inflated beyond the cost of equity for the proxy group studied, includes unnecessary and non-market-based adjustments related to financial leverage, the Company's size, flotation costs, and the Company's claim of superior management performance. Importantly, the Company's claim of superior management performance is belied by the evidence presented in this case. The Commission should give little weight to the Company's proposals and, instead, grant significant weight to the OCA's recommendation because it is directly tied to the financial analyses conducted by OCA witness Garrett as to investors' expected rate of return for ratemaking purposes.

Cost of Service, Revenue Allocation, and Rate Design

While the cost of service study relied upon by Columbia for the purposes of revenue allocation and rate design is reasonable, as all parties who submitted testimony on this issue except PSU agree, the Company's revenue allocation and rate design proposals would not result in just and reasonable rates. OCA witness Mierzwa's recommendation to reduce the

subsidies provided to Columbia's large commercial and industrial class by its residential and small commercial and industrial classes should be granted significant weight as they are cost-based and are consistent with the principles of gradualism.

Further, the Commission should reject the Company's proposal to increase the residential customer charge by 85%. Columbia currently charges the highest residential customer charge of any NGDC in the Commonwealth. Further, the Company's proposal includes costs which do not vary directly with the addition or subtraction of a single customer, such as the cost of mains or uncollectible expense, and should not be included in a customer charge. Columbia's proposed residential customer charge also violates the principle of gradualism, reduces customers' incentives to conserve energy, and creates unaffordability concerns for low-income customers in its service territory. For these reasons, the OCA requests that the Commission grant substantial weight to the evidence presented by OCA, I&E, and CAUSE-PA that the Company's residential customer charge should remain at its current level of \$17.25.

Weather Normalization Adjustment

The Company's proposal to implement a permanent Weather Normalization Adjustment (WNA) should be denied. Considering the proposed WNA through the lens of the Commission's fourteen policy factors, the weight of the policy factors indicates that the proposed WNA does not result in just and reasonable rates. Further, during the twelve heating seasons during which Columbia's WNA Pilot operated, customers have paid an additional \$74 million in rates to the Company without receiving any benefit, especially not in the past five years during which there were no net credits to customers. Columbia's

customers who testified regarding the WNA Pilot expressed concern over the one-sided nature of the Pilot WNA or the WNA's recovery of throughput-related costs for natural gas they did not consume.

The proposed WNA would likely continue to operate solely to the Company's benefit while having detrimental effects on Columbia's customers' incentives to conserve and disproportionately harming low-income customers. The Commission recently denied a proposed permanent WNA with similar characteristics to Columbia's and the OCA respectfully requests that the Commission deny Columbia's request to implement the proposed permanent WNA as well because it would not result in just and reasonable rates.

Revenue Normalization Adjustment

The Company's proposal to implement a permanent Revenue Normalization Adjustment (RNA) should be denied. Under the Commission's fourteen policy factors regarding alternative ratemaking mechanisms, the weight of the evidence presented in this case clearly demonstrates that the proposed RNA would not result in just and reasonable rates. Instead, the proposed RNA will almost certainly operate to increase customers' rates without being tied to any potential benefit to consumers. Columbia did not submit evidence that the proposed RNA would help Columbia improve its reliability, ability to invest in safety-related plant improvements, or decrease the frequency of its near-annual rate increase requests.

Further, the RNA has no basis in cost of service. The proposed RNA recovers demand- and throughput-related costs which are included in the variable distribution portion of customers' bills through a fixed monthly surcharge, contrary to the

Commission's clear precedent that such costs are recovered through volumetric rates. Through the use of the FPFTY and near-annual rate filings, Columbia already receives timely recovery of its investment in reliability- and safety-related plant improvements. The virtual guarantee of cost recovery that the proposed RNA offers would diminish Columbia's incentives to control costs and would likely lead to higher rates over time. The RNA would also recapture customers' savings on the distribution portion of their bill due to reduced consumption, contrary to the Commission's policy promoting conservation and energy efficiency. The Commission recently reached a similar conclusion in Columbia's 2020 rate case and Pennsylvania-American Water Company's 2023 rate case.

In sum, Columbia failed to meet its burden of proof that the RNA is necessary to provide safe, adequate, and reliable service or that it is otherwise a just and reasonable rate mechanism and, therefore, the OCA respectfully requests that the Company's proposal to implement an RNA should be denied.

Customer / Quality of Service

The OCA recommends several improvements to Columbia's quality of customer service. Currently, Columbia does not adequately investigate potential system-wide causes of customer disputes and complaints, establish payment arrangement terms in which its customers can succeed, or educate its field representatives on proper personal contact procedures. Further, the Company's billing and payment practices regarding shopping for natural gas suppliers and the use of automated chat boxes may be inadequate to ensure that customers are adequately informed about their bill or their rights under the Commission's regulations. The OCA requests that the Commission implement the recommendations of

its expert, OCA witness Alexander, to ensure that Columbia's service is adequate and reasonable.

Universal Service Programs

Due to the frequency and magnitude of Columbia's rate increase requests, its customer base is battling increasing unaffordability of natural gas bills. The OCA requests that the Commission consider Columbia's customers' ability to afford the rate increase authorized in this proceeding when authorizing Columbia's revenue requirement increase or decrease which has a pronounced effect on Columbia's low- and moderate-income customer base. The OCA also recommends several improvements to the Company's universal service programming. Columbia should improve its identification of low-income customers and undertake greater efforts to ensure low-income customers are not disconnected from service and are timely reconnected. The OCA supports the Company's requested arrearage forgiveness pilot because it will help re-enroll CAP customers who would otherwise be unable to re-enroll due to a high arrearage balance. However, the OCA recommends that the Company's request to recover universal service administrative costs through the Rider USP should be denied because the administrative costs identified by Columbia do not fall within the narrow definition of costs eligible for recovery through the Rider USP. The OCA submits that implementation of its recommendations in this proceeding regarding affordability and universal service programs will be a significant benefit to the Company and its customer base by reducing costs associated with uncollectibles and terminations and by ensuring that as many Columbia customers retain natural gas distribution service as possible.

Energy Efficiency Programs

The OCA supports Columbia's proposed continuation of its Energy Efficiency Plan into its second phase. The benefits associated with the Plan far outweigh the costs by maximizing affordable energy efficiency and demand-side management measures available to Columbia's customers. Columbia largely adopted the recommendations of the OCA regarding necessary improvements to the Plan. However, the OCA continues to recommend that an independent third-party evaluator should measure the success of the Plan. By adopting the OCA's proposed improvements to the Plan, the Commission would ensure that not only is Columbia able to offer energy efficiency programming to its customers, but also that the Company's offerings will provide the most benefit to the most customers.

Rate EDDS

The OCA recommends that the Company's proposal to implement an Economic Development Distribution Service Rate (Rate EDDS) tariff be denied. At this time, Columbia has no prospective customers to receive service under this tariff. Therefore, the Company's request is premature, as the Commission cannot know the usage characteristics of the customer to be served and how those characteristics are considered in the cost of service studies.

Eligible Customer Lists

The OCA recommends that the Commission disallow Columbia's proposal to modify its tariff to expand the customer information it can provide to natural gas suppliers and third-parties through Columbia's Eligible Customer Lists. The Company's proposed

tariff revision raises significant customer privacy concerns, especially when it is unclear to which third-parties Columbia will provide customers' contact information, including their email address. Columbia recently filed a letter indicating that it plans to implement on-bill billing for non-basic services and receive compensation for on-bill billing services. The OCA is concerned with the proposed expansion of the information Columbia provides to undisclosed third-parties paired with its desire to begin on-bill billing. As such, to protect customers' personal information and privacy from disclosure to unidentified third-parties, the OCA respectfully requests that the Company's proposals be denied.

III. OVERALL POSITION ON RATE INCREASE

A. Overall Position on Rate Filing

Columbia's request for an additional \$110.5 million in annual revenue far exceeds the amount of revenue necessary for it to provide safe, reliable, and adequate service at just and reasonable rates to its 446,000 customers. Instead, Columbia could provide safe and adequate service at just and reasonable rates with an annual revenue decrease of \$36.3 million.

Currently, Columbia already collects the highest revenue per unit of natural gas in the Commonwealth, and the third-highest for the 25 NGDCs offering service in the mid-Atlantic region, surpassed only by NGDCs offering service to New York City.¹¹¹ This is, in part, because Columbia has requested a rate increase 10 times since 2009, including five

¹¹¹ OCA Exh. MWD-7.

rate increases requested since 2020.¹¹² The continued upwards pressure on rates for Columbia’s captive customers due to its frequent requests for greater revenues is driving an affordability crisis in its service territory, exacerbated by recent and current economic conditions.¹¹³ Low-income customers, middle-income customers, and seniors with fixed incomes are the hardest hit.¹¹⁴ It is in both the utility’s interest and customers’ interest that rates remain affordable.¹¹⁵

Columbia is required to “furnish adequate and reasonable service to the public, and it is allowed to charge such just and reasonable rates as will enable it to properly function.”¹¹⁶ The OCA agrees with and supports this foundational assertion of public utility regulation. However, the Company’s proposals far exceed the rates required to enable the Company to provide adequate and reasonable service.

One of the Company’s primary concerns is ensuring recovery of all costs associated with satisfying its “obligation to serve and the fixed expense incurred associated with that obligation.”¹¹⁷ The Company does bear an obligation. In exchange for its obligation, the Company receives a monopoly franchise and an opportunity to recover a return of all prudently incurred expenses and capital investment, as well as a return on the value of

¹¹² OCA St. 5 at 7. The OCA notes that the Company’s rate increase request filed in 2019 at docket number R-2019-3010039 was subsequently withdrawn.

¹¹³ *Id.* at 32-41.

¹¹⁴ *Id.* at 38, 46.

¹¹⁵ *Pa. PUC v. Roaring Creek Water Co.*, 73 Pa. PUC 373, 400 (1990) (*Roaring Creek 1990*) (affordability “is in both the shareholders’ and ratepayers’ best interest. Affordable bills will maximize revenues for the Company and will enable ratepayers to continue to receive an essential service.”).

¹¹⁶ *Pittsburgh v. Pa. PUC*, 128 A.2d 372, 383 (Pa. Super. 1956) (*Pittsburgh 1956*).

¹¹⁷ Columbia St. 1 at 9-11.

property placed into public service; Columbia does not face risks associated with a competitive market, which would not guarantee a captive customer base or the opportunity to earn.¹¹⁸ This is the bargained-for exchange known as the regulatory compact.¹¹⁹

However, the regulatory compact requires checks on utilities in order to function, including ensuring that a utility does not abuse its monopoly franchise and captive customer base in a manner which would not be permissible in a competitive market.¹²⁰ As stated by OCA witness Deupree, “[r]egulatory lag has long been recognized as a key component of the overall regulatory compact given the discipline it can impose on utility operational and investment decisions.”¹²¹ In the time between rate cases, a utility must be disciplined in how it incurs expenses and makes capital investment.¹²² The General Assembly has determined that regulatory lag should not affect plant investment relating to safety and reliability and that some regulatory lag is appropriately mitigated through the use of a forecasted test year.¹²³ The current ratemaking tools to address regulatory lag, therefore, “demonstrate[] the recognition that the beneficial impact of regulatory lag must be tempered by other processes that incentivize utilities to make investments in non-revenue generating improvements that are in the public interest.”¹²⁴ The remaining effects of regulatory lag – to the extent they are felt by a utility which files annual or near-annual

¹¹⁸ *Pittsburgh 1956*, 128 A.2d at 382-383.

¹¹⁹ OCA St. 1 at 14.

¹²⁰ OCA St. 1 at 9.

¹²¹ *Id.* at 7-9.

¹²² *Id.* at 8.

¹²³ 66 Pa. C.S. §§ 315(e), 1353.

¹²⁴ OCA St. 1SR at 4-5.

rate cases – reduce incentives to overcapitalize and increase incentives to cost efficiencies, which are beneficial to ratepayers by reducing a utility’s long-term costs.¹²⁵

While Columbia seeks to undermine this cornerstone of public utility regulation in the interests of pursuing revenue stability, no evidence indicates that it is unable to earn sufficient revenue to comply with its obligation to serve and provide reliable, safe, and adequate service or that, in the absence of revenue stability mechanisms, it is deprived of a reasonable opportunity to earn its authorized revenue requirement.¹²⁶ Namely, despite decreasing usage per customer trends, the Company’s revenue per customer has continued to increase over time.¹²⁷ OCA witness Deupree testified that, “[i]f anything, the challenge for the Company has been, and continues to be, its cost efficiencies... revenues are not the problem and offering the Company any form of revenue cushion or insulation only makes it whole for continued cost inefficiencies.”¹²⁸

Nevertheless, in pursuit of revenue stability, Columbia requests that its volumetric risks be shifted entirely to ratepayers through customer charges above the indicated customer-related cost of service, the conversion of its sunseting Weather Normalization Adjustment (WNA) Pilot into a permanent mechanism, and the implementation of a

¹²⁵ OCA St. 1 at 11.

¹²⁶ OCA St. 1 at 6, 16, 39, 56 (“The Company has not demonstrated that the existing regulatory framework in Pennsylvania is failing to support timely and adequate cost recovery. Rather, the evidence, including statements made by its parent company, suggests that regulatory lag is already being effectively managed. The Commission should reaffirm the value of regulatory lag as a structural feature of traditional ratemaking and recognize that further erosion of this principle is neither necessary nor justified in this case.”).

¹²⁷ OCA Exh. MWD-5.

¹²⁸ OCA St. 1 at 27-28.

Revenue Normalization Adjustment (RNA).¹²⁹ Columbia has provided no evidence of benefit to consumers through these initiatives.¹³⁰ Rather, Columbia seeks to provide the same level and quality of service and request rate increases with the same frequency while eliminating risks inherent in its own ability to perform.¹³¹

Columbia is a large, technically and financially fit public utility that has been providing natural gas distribution service for over half a century.¹³² Its parent company, NiSource, owns five other natural gas utilities in five different states, as well as an electric utility.¹³³ Columbia is well aware of the risks inherent in providing natural gas distribution service, including that customers' usage of natural gas has been declining over time as a result of improved efficiency in home appliances and reduced throughput for heating purposes.¹³⁴ This is why usage reduction trends are reflected in the Company's calculation of its billing determinants for the purposes of designing rates.¹³⁵ The billing determinants used by Columbia, which were not challenged by any party in this proceeding, establish that the current customer and volumetric charge structure are sufficient to meet the

¹²⁹ Columbia St. 1 at 9; Columbia St. 6 at 13-14.

¹³⁰ *See, e.g.*, OCA St. 1 at 40-41 (noting that utility commissions approving decoupling mechanisms have recognized the shift in risk from the utility to its ratepayers); OCA St. 1 at 55 ("Regulatory policy disfavors mechanisms that allow utilities to recover lost revenues or costs from customers without also exposing the utility to comparable downside risk or performance standards.").

¹³¹ OCA St. 1 at 30-39 ("The Commission simply cannot adopt regulatory policies and strategies that offer zero ratepayer benefits and run the further risk of making Columbia's already worse-in-class retail natural gas rates any worse.").

¹³² Columbia St. 1 at 3.

¹³³ OCA Exh. MWD-8.

¹³⁴ *See* Columbia St. 2 at 10-12.

¹³⁵ *Id.*

Company's revenue requirement. That is all that is required for the Company to have a reasonable opportunity to recover its authorized revenue: the inclusion of revenue stability assurances for the Company, regardless of its performance, merely increase rates to the Company's captive customers without providing more efficient or satisfactory service.¹³⁶

The Company's request is a prime example of a utility's attempt to engage in monopolistic excess and maximize the revenue extracted from its captive customers. While "[i]t must be recognized that there is always the desire of the utility to get as large a return as possible," there is likewise "a desire on the part of the ratepayer to buy as cheaply as possible. Only the Commission can stand between the public and the utility. It is almost the only protection which the public has."¹³⁷ "The commission is charged with the duty of protecting the rights of the public."¹³⁸

In this case, it is necessary for the Commission to act on its duty and protect Columbia's ratepayers from the Company's rate increase request and attempt to reduce or eliminate the risk it bears by shifting that risk onto ratepayers without commensurate benefit. Ratemaking is a prospective exercise designed to incentivize favorable customer and utility behavior over time, as determined by the Commission. The Company's rate increase request is excessive and threatens the long-term affordability and energy efficiency goals of its customers while removing or reducing incentives for the Company

¹³⁶ *Phila. Suburban Transp. Co. v. Pa. PUC*, 281 A.2d 179, 186-87 (Pa. Cmwlth. 1971) ("rates must be designed to furnish the most efficient and satisfactory service at the lowest reasonable price for the greatest number of customers, i.e., the public generally").

¹³⁷ *Pittsburgh v. Pa. PUC*, 82 A.2d 515, 517 (Pa. Super. 1951) *otherwise modified in Pittsburgh v. Pa. PUC*, 88 A.2d 59 (Pa. 1952) (*Pittsburgh 1951*).

¹³⁸ *Citizens Water Co. v. Pa. PUC*, 124 A.2d 123, 126 (Pa. Super. 1956).

to be disciplined with expenses and investments. For these reasons, set forth more fully below, the OCA respectfully requests that the Commission authorize a rate decrease in this proceeding of \$36.3 million.

B. Overall Position on Revenue Requirement

Columbia requests a \$110,444,676 revenue requirement increase.¹³⁹ OCA witness Mugrace calculated a \$36,316,933, or 3.96%, revenue requirement decrease at OCA witness Garrett's 7.06% overall rate of return recommendation, which includes an 8.9% return on equity.¹⁴⁰ OCA witness Mugrace's overall recommended adjustments are as follows:

- Rate base balance should be set at \$3,861,622,942, which is \$16,241,227 higher than the Company's proposed rate base balance of \$3,845,381,715.
- Rate of return on rate base should be set at \$272,630,580, which is \$56,149,557 lower than the Company's claimed amount of \$328,780,137. The difference is based on OCA witness Garrett's recommended rate of return of 7.06%, which includes a recommended return on equity of 8.90% and a capital structure consisting of 47.68% long-term debt, 2.32% short-term debt, and 50% common equity.
- Operating revenue at present rates should be set at \$919,077,834, which is the same as Company's present rate revenue of \$919,077,833.
- Operating expenses should be set at \$565,003,970, which is \$62,987,939 lower than the Company's proposed operating expenses of \$627,991,908.
- Requested revenue requirement annual increase should be reduced by \$63.615 million, based upon OCA witness Garrett's recommendation to set depreciation expense balance at \$84,887,176 using the average

¹³⁹ OCA St. 2SR at 1.

¹⁴⁰ OCA St. 2SR at 4.

life group (ALG) procedure, which is \$45,802,423 lower than the Company's claimed depreciation expense balance of \$130,689,599 using the equal life group (ELG) procedure.

- Income tax expense should be \$55,267,855, which is \$17,543,486 lower than the Company's proposed income taxes of \$72,811,341. OCA witness Mugrace accepted the Company's Proposed Investment Tax Credit of \$(78,757).
- Overall, based on the recommendations of OCA witnesses Mugrace and Garrett, the OCA recommends an overall revenue requirement annual decrease of \$36,316,933, which is \$146,813,730 lower than the Company's proposed revenue requirement annual increase of \$110,496,797.¹⁴¹

IV. RATE BASE

A. Plant in Service – Inflation Adjustment.

Columbia is projecting net plant additions (gross plant additions less retirements) of \$436,529,280 for the future period ending November 30, 2025, and an additional \$436,492,629 for the fully projected future test year period ending December 31, 2026.¹⁴²

In reaching these totals, Columbia included an inflation rate factor of 4% for 2025 and 5% for 2026.¹⁴³ OCA witness Mugrace recommended disallowing the inflation rate factor adjustments as follows:

I am recommending disallowance of inflation related adjustments because these types of adjustments or costs are not known and measurable in setting rates for service. These types of cost adjustments should not be used for ratemaking purposes because they do not provide a good index of cost increases, but rather reflect an overall broad, blanket-type economic adjustment that are typically applied to baskets of goods and services that may or may not be related or reflective to costs that are expected to be incurred by Columbia. Inflation related adjustments do not address any

¹⁴¹ OCA St. 2SR at 4.

¹⁴² OCA St. 2 at 4; Columbia Exhibit 108 at 3.

¹⁴³ OCA St. 2 at 7.

particular or individual expense category. These adjustments are simply forecasts or predictions that may or may not be realized. As baskets of goods and services fluctuate over time, applying inflation adjustments even from a budgeting standpoint is not a proper approach that should be utilized in setting rates for utility services. While such inflation adjustments are normally used to develop economic data as in changes to consumer goods and services, utilizing an inflation related adjustment for ratemaking purposes is not reasonable.¹⁴⁴

The use of broad inflation adjustments to estimate the cost of additional plant undermines the ratemaking concept of “used and useful” and certainly does not rise to the level of meeting Columbia’s burden of proof in this proceeding.¹⁴⁵ The Commission has repeatedly required specificity by the utility when the utility uses an inflation factor to estimate cost increases in the test year, and the Commission has disallowed inflation factors that are too speculative in nature.¹⁴⁶ In *Aqua 2022*, the Commission stated, “allowing Aqua to apply a general inflation adjustment to a block of expenses could incentivize less accurate tracking of expenses and a less rigorous approach to controlling costs for those

¹⁴⁴ OCA St. 2 at 7-8.

¹⁴⁵ See 66 Pa. C.S. § 102 (defining “Rate base” as “[t]he value of the whole or any part of the property of a public utility *which is used and useful* in the public service”) (emphasis added); see also 66 Pa. C.S. § 315(e) (permitting the use of a FPFTY in discharging the burden of proof); see also *Pa. PUC v UGI Utilities, Inc-Electric Division*, R-2017-2640058, Order (Oct. 25, 2018) (*UGI 2018*) at 27-31, 79 (rejecting the utility’s rate base and related expense claims in the FPFTY because the utility did not demonstrate by the close of the record that there would be “reasonable certainty” that the claimed plant would “be in operation” and thus used and useful in the FPFTY); see also 66 Pa.C.S. § 315(a) (utility bears the burden of proving the justness and reasonableness of every element of its requested rate increase); *Burleson*, 461 A.2d at 1236.

¹⁴⁶ *Pa. PUC v. Phila. Elec. Co.*, 58 Pa. P.U.C. 7 (1983) (*PECO 1983*); *Nat’l Fuel Gas Dist. Corp. v. Pa. PUC*, 677 A.2d 861 (Pa. Cmwlth. 1986) (*NFG 1986*).

expenses.”¹⁴⁷ Additionally, the Commission found that Aqua’s “application of a General Price Adjustment to 22% of expenses is neither targeted nor specific.”¹⁴⁸

Here, Columbia has not met its burden of proving how the cost of inflation Columbia requested to add to its rate base constitutes used and useful plant in the FPFTY. Instead, Columbia’s witnesses stated in rebuttal that they did not agree with OCA witness Mugrace’s adjustments to remove inflation.¹⁴⁹ OCA witness Mugrace replied as follows:

As I stated in my direct testimony, inflationary adjustments are not known and measurable and they do not accurately provide the true costs of adjusting costs. Inflationary related costs are typically blanket increases that are applied to all costs. Costs should be predicated upon known and measurable concepts. These types of inflation-related adjustments do not provide a good index or pattern of increased costs over time. While such types of inflationary increases are useful to develop economic data, they should not be used to develop and set rates for utility service under a ratemaking methodology. Rates once set are collected until they change in another rate case and thus have to be set as just and reasonable rates. The Company has not provided any additional information or evidence showing that these cost increases will be realized or be present in its FPFTY period. If inflation costs were utilized, and if those costs did not materialize when rates are set by the Commission, the Company will recover costs greater than its cost of service and over-recover costs which ratepayers will not be able to get back. I continue to recommend the disallowance of the 4% and 5% of inflationary costs in 2025 and 2026 related to the Company’s capital expenditure replacements. Further, Mr. Vassalotti’s argument that disallowance of these inflation costs would diminish a utility’s ability to meet its cost of service requirement and earn its allowed rate of return is without merit. The Company has the opportunity to recovery [sic] its known and measurable costs and earn its rate of return; it is not a guarantee of 100% recovery. Inflation / Deflation costs are not the sort of adjustments that should be used to set rates for utility services. Mr. Vassalotti is correct to state that Inflation/Deflation costs are

¹⁴⁷ *Pa. PUC v Aqua Pa. Water Co.*, 2022 Pa. PUC LEXIS 161, *50-51. (Order entered May 16, 2022) (*Aqua 2022*).

¹⁴⁸ *Id.* at *51.

¹⁴⁹ OCA St. 2SR at 5.

used for economic data. However, they should not be used for ratemaking purposes to set the revenue requirement recovery from ratepayers.¹⁵⁰

Columbia provided no evidence supporting that its inflation adjustments described above are accurate representations of the costs which the Company knows will be incurred. Data provided by the Company indicates that its inflation factors were calculated using historical inflation data, which is an inaccurate representation of what levels of inflation will actually be experienced in the future.¹⁵¹ By failing to establish a factual or evidentiary basis for the actual, specific inflation factors utilized, Columbia should not be able to recover such costs, as it bears the burden of proof.¹⁵²

Given that the Company has not met its burden of proof, the Commission should adopt OCA witness Mugrace's recommendation to disallow the Company's request to apply 4% and 5% inflation rates to arrive at total 2025 and 2026 capital expenditure replacements. Disallowance will result in a revenue requirement decrease of approximately \$1.42 million.¹⁵³

B. Accumulated Depreciation

The OCA recommends two adjustments to the Company's accumulated depreciation reserve. Accumulated depreciation "is a measure of the state of the system at any given time" and includes the sum of depreciation accruals collected through depreciation rates over the life of plant placed into service, also referred to as the

¹⁵⁰ OCA St. 2SR at 5-6.

¹⁵¹ OCA St. 2SR at 5-6.

¹⁵² 66 Pa. C.S. § 315(e).

¹⁵³ OCA St. 2SR at 6; OCA Exh. DM-SR-5.

“depreciation reserve.”¹⁵⁴ Accumulated depreciation is expressed as a negative value and is applied to utility plant in service, in addition to other rate base adjustments, to calculate the net plant in service value on which a utility earns a return.¹⁵⁵

The first adjustment recommended by OCA witness Mugrace to the Company’s claimed accumulated depreciation reserve is based on his adjustment to the Company’s utility plant in service account. As described *supra*, OCA witness Mugrace recommended an adjustment of \$(14,507,711) to Columbia’s claimed utility plant in service amount.¹⁵⁶ Mr. Mugrace explained his adjustment to the associated claim for accumulated depreciation on that utility plant in service as follows:

As I have recommended disallowance of \$14,507,711 (Exhibit DM-5) to reduce the Company’s UPIS claim and so remove inflation related capital costs related to contractor costs, a corresponding adjustment to the Company’s FPFTY Accumulated Depreciation expense claim is also necessary. Since the Company has included inflation related adjustments in its capital expenditure additions, depreciation is based upon total costs of Company capital expenditures and therefore is the basis to the development of depreciation expenses. I utilized OCA witness Mr. Garrett’s recommended depreciation rate related to mains (account 376) of 1.63% multiplied by the \$14,507,711.¹⁵⁷

Based on Mr. Mugrace’s calculation, he recommends an adjustment of \$(236,476) to accumulated depreciation based on his recommended reduction to the Company’s utility plant in service balance.¹⁵⁸

¹⁵⁴ OCA St. 3, App’x C.

¹⁵⁵ OCA St. 3 at 49 (providing the equation used to calculate the revenue requirement for regulated utilities).

¹⁵⁶ *Supra* at Section IV.A.

¹⁵⁷ OCA St. 2 at 9.

¹⁵⁸ *Id.*; see also OCA Exh. DM-6, DM-32.

Mr. Mugrace's second adjustment is based on the recommendation of OCA witness Garrett that the Company utilize the ALG procedure instead of the ELG procedure when calculating its depreciation rates for the purposes of depreciation expense.¹⁵⁹ Because accumulated depreciation represents the sum of depreciation expense collected by the Company over the life of its plant in service, an adjustment to depreciation expense requires a corresponding reduction to the depreciation reserve.¹⁶⁰ OCA witness Garrett recommended an overall reduction to Columbia's depreciation expense claim of \$45,802,423.¹⁶¹ Based on Mr. Garrett's recommended adjustment, Mr. Mugrace made a corresponding reduction to Columbia's claimed accumulated depreciation of \$45,802,423.¹⁶² While the Company disagreed with the basis of Mr. Mugrace's adjustment, it did not present evidence indicating that the proposed adjustment was inaccurate.¹⁶³ As a result, if the Commission adopts the OCA's recommended adjustment to depreciation expense, Mr. Mugrace's adjustment to accumulated depreciation should be adopted as well. The OCA presents further arguments as to proper accumulated depreciation balance in the section of this brief addressing Deprecation Expense and incorporates those arguments herein.

Due to the OCA's two recommended adjustments of \$(236,476) and \$(45,802,423), OCA witness Mugrace recommended that an overall reduction of \$46,038,899 to the

¹⁵⁹ OCA St. 2 at 10; OCA St. 3 at 61-66.

¹⁶⁰ OCA St. 3, App'x C at 6.

¹⁶¹ OCA Exh. DJG-17.

¹⁶² OCA St. 2 at 10; OCA Exh. DM-SR-6.

¹⁶³ Columbia St. 5-5 at 32.

Company's claimed depreciation reserve of \$927,212,098 for an overall recommended balance of \$881,173,199.

C. Cash Working Capital

In its filing, Columbia only included a cash working capital claim for its materials and supplies, prepayments and gas storage underground balances.¹⁶⁴ However, OCA witness Mugrace testified that “[t]he Company’s claim is overstated by the application of inflation adjustments to certain components of the Company’s claim particularly its Materials and Supplies and its Prepayments.”¹⁶⁵

OCA witness Mugrace removed the Gross Domestic Product (GDP) inflation factor of 2.93% for 2025, and the 3.05% GDP inflation factor for 2026.¹⁶⁶ OCA witness Mugrace testified:

As I indicated above in my adjustments related to the Company’s [Utility Plant in Service], I believe that including inflation type factors to adjust for costs are not reasonable because these types of increase adjustments are not known and measurable and they do not reflect the true costs of providing service. Inflation adjustments do not provide a good index of cost increases but rather an overall broad blanket-type economic adjustment that are [sic] typically applied to goods and services that may not be directly rated to costs incurred by the Company. Inflation adjustments do not address any particular or individual expense category. These are simple forecasts and predictions of cost estimates. As goods and services fluctuate over time, applying escalating or inflation factors to adjust costs is not a proper approach that should be utilized in setting rates for service. While such inflation types adjustments are used to develop economic data as in changes to broad baskets of consumer goods and services such as housing, clothing, food, etc., utilizing adjustments for ratemaking purposes is not reasonable. More

¹⁶⁴ OCA St. 2 at 10; Columbia Exh. 108.

¹⁶⁵ OCA St. 2 at 10-11.

¹⁶⁶ OCA St. 2 at 11.

definitive types of increases are contractually related increases or escalation increases that are included in agreements or services contracts.¹⁶⁷

OCA witness Mugrace's adjusted cash working capital balance represents a reduction for materials and supplies of \$56,977 and a reduction of prepayments of \$262,481 for a net decrease of \$319,457.¹⁶⁸ This reduces Columbia's working capital balance to \$56,625,024.¹⁶⁹

D. Accumulated Deferred Income Taxes (ADIT)

The OCA recommends that Columbia's ADIT balance be reduced by \$67,372.¹⁷⁰ This reduction corresponds to OCA witness Mugrace's recommendation to remove the inflation-related adjustments Columbia used to calculate its plant additions for 2025 and 2026.¹⁷¹ This results in a \$916,650 decrease to Columbia's revenue requirement.¹⁷²

In calculating this adjustment, OCA witness Mugrace accepted Columbia witness Harding's adjustment to depreciation expenses calculation reflecting a decrease in tax repairs, mixed service costs, and reduction in capital expenditures, which results in a \$41,409,747 depreciation expense.¹⁷³ Additionally, OCA witness Mugrace accepted Ms. Harding's update related to excess tax depreciation over book depreciation of \$32,331,282,

¹⁶⁷ OCA St. 2 at 11.

¹⁶⁸ OCA St. 2 at 12.

¹⁶⁹ OCA St. 2 at 12; OCA Exh. DM-3.

¹⁷⁰ OCA St. 2 at 13; OCA Exh. DM-7.

¹⁷¹ OCA St. 2 at 13; OCA Exh. DM-7.

¹⁷² OCA St. 2SR at 7.

¹⁷³ OCA St. 2SR at 7.

which represents the state income tax flowthrough net of federal tax benefits.¹⁷⁴ As such, OCA witness Mierzwa's updated ADIT balance is \$8,696,054.¹⁷⁵

E. Materials & Supplies/Prepayments

For the materials and supplies/prepayments adjustment, OCA witness Mugrace testified that he "disallowed this inflation adjustment and calculated a non-inflated balance of \$891,093."¹⁷⁶ OCA witness Mugrace further testified as follows:

The Company reflected a 2025 13-month average balance of \$5,470,802. Included in that balance is an inflation adjustment of 2.93% (Statement No. 11-R at 2). I disallowed this inflation adjustment and calculated a non-inflated balance of \$5,315,070. There was no need to include the 2026 inflation adjustment of 3.05% because my adjustment sets the Prepayments at the 2025 level at actual costs with no further adjustment needed. The Company proposed 2025 13-month average balance of materials and supplies included a 2.93% inflation factor. The same holds true for the Company's Prepayments.¹⁷⁷

As shown above, while Company witness Covert argued that OCA witness Mugrace removed only the 2025 2.93% GDP deflator and the 2026 3.05% GDP deflator¹⁷⁸, there is no need to include inflation or deflation adjustments as OCA witness Mugrace sets the prepayments as well as the materials and supplies balance at the 2025 actual cost level with no further inflationary adjustments needed.¹⁷⁹ This adjustment reduces the revenue requirement by approximately \$31,280.¹⁸⁰

¹⁷⁴ *Id.*

¹⁷⁵ OCA St. 2SR at 7-8; OCA Exh. DM-SR-7.

¹⁷⁶ OCA St. 2SR at 8.

¹⁷⁷ *Id.*

¹⁷⁸ Columbia St. 11-R at 2.

¹⁷⁹ OCA St. 2SR at 8.

¹⁸⁰ OCA St. 2SR at 5.

F. Consolidated Income Tax Adjustment

The OCA recommends that Columbia be required to commit 50% of its consolidated tax expense adjustment, or \$2,263,821, to utility working capital.¹⁸¹ This adjustment reduces the revenue requirement by approximately \$2.359 million.¹⁸²

Under Act 40 of 2016, codified at Section 1301.1 of the Code, regulated public utilities are required to used 50% of excess rates collected for the purpose of paying income tax “to support reliability or infrastructure related to the rate-base eligible capital investment” and 50% for “general corporate purposes.”¹⁸³

As Columbia is expected to invest \$316.8 million of infrastructure projects in the FTY and an additional \$329.3 million in the FPFTY period, this expenditure is greater than the \$2.26 million (50% of the \$4.53 million differential) that would have been a consolidated tax adjustment prior to Act 40.¹⁸⁴ However, Columbia has not specifically identified how it the 50% differential would be used for general corporate purposes.¹⁸⁵ Indeed, Columbia did not provide any specifics as to whether the 50% of the differential would be used in any way to benefit Pennsylvania ratepayers.¹⁸⁶ OCA witness Mugrace testified that “one might conclude from this that Columbia therefore basically intends to use that money for the benefit of its stockholders and not apply it in any manner to provide

¹⁸¹ OCA St. 2 at 48.

¹⁸² OCA St. 2SR at 9; OCA Exh. DM-SR-3.

¹⁸³ 66 Pa. C.S. § 1301.1.

¹⁸⁴ OCA St. 2 at 47.

¹⁸⁵ OCA St. 2 at 47.

¹⁸⁶ OCA St. 2 at 47.

a quantifiable ratepayer benefit or in a manner that directly benefits service to Pennsylvania customers.”¹⁸⁷

The OCA submits that the Company should dedicate the additional funding towards a corporate purpose which benefits ratepayers. OCA witness Mugrace testified:

Because Columbia is a regulated utility in Pennsylvania, its “general corporate purpose” is to provide regulated utility service in the Commonwealth of Pennsylvania. While the term “general corporate purposes” is rather vague, consistent with that general corporate purpose of regulated utilities, general corporate purposes would include uses for such “differential” revenues as supporting capital expenditures necessary to execute utility business plans, paying off debt, funding construction projects, paying dividends, paying for maintenance and operating expenses, investing in utility plant in Pennsylvania, and providing a source of working capital. Many of these uses for “general corporate purposes” would have a quantifiable benefit to Pennsylvania ratepayers. As I read the entirety of Act 40, the “revenue use differential” addressed in the Act for “general corporate purposes” should mean public utility purposes and uses that result in having some identifiable and quantifiable benefit...¹⁸⁸

As Columbia chose to be vague rather than specific, the OCA has no reassurance that these funds will appropriately benefit ratepayers and recommends that the balance of the consolidated tax expense adjustment be used as a source of non-investor-supplied funding for utility working capital.¹⁸⁹ This would reduce the revenue requirement that is necessary to be collected from ratepayers by \$2.359 million.¹⁹⁰

¹⁸⁷ OCA St. 2 at 47.

¹⁸⁸ OCA St. 2 at 47-48.

¹⁸⁹ OCA St. 2 at 48.

¹⁹⁰ OCA St. 2SR at 9; OCA Exh. DM-SR-3.

G. Conclusion

The OCA's recommended rate base balance is \$3,861,622,942, which is \$16,241,227 higher than the Company's proposed Rate Base balance of \$3,845,381,715.¹⁹¹ The OCA recommends the removal of the portion of rate base which constitutes "inflationary adjustments" for the FTY and FPFTY that are not supported by sufficient evidence but rely on inflation factors to support additions to rate base that are not tied to specific projects, plant accounts, or other measures of rate base. The OCA's remaining adjustments to the Company's rate base balance – those regarding accumulated depreciation, cash working capital, and accumulated deferred income tax – flow from other adjustments to rate base, depreciation expense, and operating and management expenses.

Columbia has not met its burden of proving the justness and reasonableness the plant claimed in rate base and all estimations or adjustments resulting from its use of a FPFTY.¹⁹² The Company's request to include such costs in its rate base balance are not adequately supported by evidence of record, are not sufficiently specific, and charging customers for such inclusions would not result in just and reasonable rates. As such, the OCA's evidence offered to support its recommended adjustments outweighs the evidence presented by the Columbia, and the OCA's adjustments should be accepted.

¹⁹¹ OCA St. 2SR at 4.

¹⁹² 66 Pa. C.S. § 315(a), (e).

V. REVENUES

The OCA did not propose any adjustments to the Company's FPFTY revenues under present rates. The OCA is not briefing this issue but reserves the right to respond in Reply Brief if necessary.

VI. DEPRECIATION EXPENSE

A. Introduction

The issue in this case is about the Company's proposed recovery of excessive amounts charged to operating expenses for annual depreciation that would lead to consumers paying unjust and unreasonable rates to the tune of \$63.615 million. The OCA carried its burden of production to show that use of the Average Life Group (ALG)¹⁹³ procedure over the Company's claimed Equal Life Group (ELG) procedure will produce just and reasonable rates. Adopting the ALG procedure is squarely within the Commission's ratemaking discretion, as no state or federal law prohibits the Commission's adoption of the ALG procedure. Substantial record evidence demonstrates that the use of the ALG procedure will permit the Company's recovery of reasonable amounts charged to operating expenses for depreciation so that the Company is whole and the integrity of its investments maintained. Substantial record evidence further demonstrates that use of the ALG procedure will allow the Company's accumulated depreciation and annual depreciation to be calculated on a reasonably consistent basis. However, the excess amounts charged in rates for depreciation expense will be removed. Furthermore,

¹⁹³ The average life group procedure is also referred to as the average service life procedure. Tr. 318.

substantial record evidence demonstrates that the use of the ELG procedure unreasonably accelerates the recovery of depreciation expense, is inconsistent with the well-established “matching” ratemaking principle and creates intergenerational inequity among consumers paying utility rates. Moreover, a significant majority of state commissions approve of the ALG procedure, leaving Pennsylvania in the small minority of jurisdictions that approve of the ELG procedure.

B. Use of the ELG procedure results in excess recovery of \$45.8 million in annual depreciation expense and a total of approximately \$63.615 million in revenue requirement, after grossing up for taxes.

The U.S. Supreme Court defined depreciation as follows: “depreciation is the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence.”¹⁹⁴

Under Pennsylvania Court precedent, annual depreciation is defined as follows: “Annual depreciation is an operating expense representing the consumption of assets in rendering service.”¹⁹⁵ “A utility is entitled under the law to recover from the rate payers the original cost of construction of its depreciable plant.”¹⁹⁶ Additionally, “it is clear in our law that ‘[i]n no event will a utility be permitted to recover by annual allowances for depreciation a total amount in excess of the original cost, since annual depreciation is

¹⁹⁴ *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 167 (1934) (*Lindheimer*).

¹⁹⁵ *Penn Sheraton Hotel v. Pennsylvania Public Utility Com.*, 198 Pa. Super. 618, 627 (Pa. Super. 1962)(*Penn Sheraton*).

¹⁹⁶ *Id.*

computed on original cost and not upon fair value or reproduction cost.’’¹⁹⁷ In other words, annual depreciation is the return *of* the investment, which is returned through the depreciation O&M expense over the life of the plant.¹⁹⁸

The Pennsylvania Superior Court defined accrued depreciation (also referred to as accumulated depreciation) as follows: “[a]ccrued depreciation for rate purposes means ‘the actual depreciation of the utility’s property as it has accrued to the date that fair value is in issue.’”¹⁹⁹ The Superior Court further noted that “accrued depreciation properly determined ‘should disclose the consumption of property to date.’”²⁰⁰

Depreciation rates are determined in a depreciation study using a depreciation system.²⁰¹ The choice of a depreciation system can significantly affect the resulting depreciation rates.²⁰² There are basic components, each with a number of variations, used to determine a depreciation system, which is then used to estimate depreciation rates.²⁰³ The basic components are: (1) methods, (2) procedures, (3) techniques, and (4) models.²⁰⁴

As OCA witness Garrett testified:

A depreciation system may be defined by several primary parameters, including: 1) a method of allocation; 2) a procedure for applying the method of allocation; 3) a technique of applying the depreciation rate; and 4) a model for analyzing the characteristics of vintage property groups. In this case, I

¹⁹⁷ *Penn Sheraton* at 627.

¹⁹⁸ OCA St. 2 at 42; OCA St. 2SR at 25; OCA Exh. DM-SR-32.

¹⁹⁹ *Penn Sheraton* at 624.

²⁰⁰ *Id.*

²⁰¹ *See* OCA St. 3 at 60.

²⁰² *See Id.*

²⁰³ *See Id.*

²⁰⁴ *See Id.*

used the straight-line method, the average life group procedure, the remaining life technique, and the broad group model.²⁰⁵

Regarding depreciation procedures, OCA witness Garrett testified that “[t]he average life’ and ‘equal life’ grouping procedures are the two most common.”²⁰⁶ In practice, depreciation experts tend to rely on either the ALG procedure or the ELG procedure, as is the case here.²⁰⁷

The primary issue before the Commission in this case regards the amounts to be recovered in operating expenses for annual depreciation and whether the ALG versus the ELG procedure should be used to determine those amounts.²⁰⁸ As OCA witness Garrett testified:

“[t]he ‘procedure’ refers to the way the allocation method is applied through subdividing the total property into groups. While single units may be analyzed for depreciation, a group plan of depreciation is particularly adaptable to utility property. Employing a grouping procedure allows for a composite application of depreciation rates to groups of similar property, rather than excessively conducting calculations for each unit.”²⁰⁹

Regarding depreciation procedure, OCA witness Garrett testified that “[w]hile single units may be analyzed for depreciation, employing a grouping procedure allows for composite application of depreciation rates to groups of similar property as opposed to excessively conducting calculations for each unit of property.”²¹⁰

²⁰⁵ *Id.* (emphasis added).

²⁰⁶ OCA St. 3, App. C at 4-5.

²⁰⁷ OCA St. 3 at 60 (emphasis added).

²⁰⁸ OCA St. 3 SR at 14.

²⁰⁹ OCA St. 3, App. C at 3.

²¹⁰ *Id.*

Currently, Columbia uses the ALG procedure for plant installed prior to 1976 and the ELG procedure for plant installed in 1976 and subsequent years.²¹¹ OCA witness Garrett testified that “[u]nder the ALG procedure, a constant accrual rate is calculated based on the average life of all property in the group.”²¹² As such, “use of the average life results in the same depreciation rate applied to each age interval.”²¹³ OCA witness Garrett further testified that “[u]nder the ELG procedure, property is divided into subgroups (also referred to as “vintages”) that each have a common life.”²¹⁴

Under the ELG procedure, depreciation expense will always be higher in early years when utilities make recent capital investments as depreciation expense is frontloaded under ELG.²¹⁵ OCA witness Garret testified as follows:

[I]n Mr. Spanos’s rebuttal testimony, I did not see him rebut the fact that compared with the ALG procedure, the ELG procedure will result in higher depreciation rates for current customers. Likewise, the ELG procedure will result in higher cash flows for Columbia relative to the ALG procedure.²¹⁶

Columbia’s use of the ELG depreciation procedure instead of the ALG procedure “has an impact of approximately \$45 million to depreciation expense as of the 2026 depreciation study.”²¹⁷ OCA witness Garrett summarized his application of the ALG procedure to Columbia’s depreciation studies as follows:²¹⁸

²¹¹ Columbia St. 5 at 4; Tr. 318-19.

²¹² OCA St. 3 at 61.

²¹³ *Id.*

²¹⁴ *Id.*

²¹⁵ OCA St. 3SR at 13.

²¹⁶ *Id.*

²¹⁷ *Id.* at 14.

²¹⁸ OCA St. 3 at 5-6.

Figure 1
Summary Depreciation Accrual Adjustment – 2024 Study

Plant Function	Columbia Accrual	OCA Accrual	OCA Adjustment
UG Storage	850,896	835,280	(15,616)
Distribution	109,087,106	69,668,279	(39,418,827)
General	1,312,807	1,313,365	558
TOTAL	\$ 111,250,809	\$ 71,816,924	\$ (39,433,885)

Figure 2
Summary Depreciation Accrual Adjustment – 2025 Study

Plant Function	Columbia Accrual	OCA Accrual	OCA Adjustment
UG Storage	180,222	180,756	534
Distribution	118,128,719	75,559,095	(42,569,624)
General	1,721,226	1,720,074	(1,152)
TOTAL	\$ 120,030,167	\$ 77,459,925	\$ (42,570,242)

Figure 3
Summary Depreciation Accrual Adjustment – 2026 Study

Plant Function	Columbia Accrual	OCA Accrual	OCA Adjustment
UG Storage	205,013	203,741	(1,272)
Distribution	128,040,495	82,237,903	(45,802,592)
General	2,444,091	2,445,532	1,441
TOTAL	\$ 130,689,599	\$ 84,887,176	\$ (45,802,423)

OCA witness Dante Mugrace testified as follows:

Based upon OCA witness Mr. Garrett's recommendation, I am continuing to include the Depreciation Expense balance adjustment of \$45,802,423. This \$45,802,423 needs to be grossed up to account for federal and state taxes. This is shown on my Exhibit DM-SR-32. My adjustment **reduces the revenue requirement by \$63.615 million.**²¹⁹

Columbia's decision to use the ELG instead of ALG procedure has an immense revenue requirement impact and represents 58% of Columbia's \$110.5 million requested revenue increase.²²⁰

C. Use of depreciation procedure is a matter of Commission ratemaking discretion to determine just and reasonable rates, and no state or federal law prohibits the Commission's adoption of the ALG procedure.

Use of a depreciation procedure is squarely a matter of Commission ratemaking discretion, as there is no state or federal law that mandates a specific depreciation procedure for conducting a depreciation analysis.

1. Case law does not prohibit the adoption of ALG procedure.

While the Company is entitled to recover depreciation expense to ensure the utility is whole and the integrity of its investment maintained, the utility bears the burden of demonstrating that its claimed amounts to recover in expenses are not excessive.²²¹ Indeed, the U.S. Supreme Court stated:

[T]he company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting

²¹⁹ OCA St. 2SR at 25-26 (emphasis added).

²²⁰ \$110.5 million x .58 (58%) = approximately \$64 million.

²²¹ 66 Pa. C.S. § 315(a); see *Lindheimer*, 292 U.S. at 169; see *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 606 (1944) (*Hope*).

system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion.²²²

Additionally, the *Hope* Court stated: “this Court recognized in [*Lindheimer*], the propriety of basing annual depreciation on cost. By such a procedure the utility is made whole and the integrity of its investment maintained. No more is required.”²²³

Importantly, the Commission is not bound by any particular methodology or procedure in determining annual depreciation expense. The Commonwealth Court stated as follows:

The [Commission] is not bound to accept any particular method in estimating accrued depreciation which is essentially a judgment figure. If the Commission based its finding on substantial evidence, it is binding upon appellate review.²²⁴

Similarly, the Superior Court stated:

It is recognized that accrued depreciation is essentially a judgment figure, based on all the evidence, and the weight to be given any particular estimate is for the commission. The commission is not bound to accept any particular method of estimating accrued depreciation.²²⁵

The only limitation on procedure is that the Commission must provide for the computation of a utility’s accumulated depreciation and annual depreciation expense on a reasonably consistent basis. Indeed, the Commonwealth Court in *Pa. Power* held that “[i]n

²²² *Lindheimer* at 169.

²²³ *Hope*, 320 U.S. at 606.

²²⁴ *Pa. Power & Light Co. v. Pa. Pub. Util. Com.*, 311 A.2d 151, 158 (Pa. Cmwlth. 1973) (*Pa. Power*) (citing *Pittsburgh v. Pa. Pub. Util. Comm’n*, 222 A. 2d 395 (Pa. Super. 1966) (*Pittsburgh*) and *Philadelphia v. Pa. Pub. Util. Comm’n*, 102 A. 2d 428 (Pa. Super. 1954) (*Philadelphia*)).

²²⁵ *Pittsburgh* 222 A.2d at 401-402 (upholding a Commission decision to give less weight to a utility’s depreciation study as the Commission had considered all relevant factors in connection with accrued depreciation).

a rate case, both annual depreciation expense allowance and accrued depreciation should be calculated on a reasonably consistent basis.”²²⁶ Moreover, “[a]lthough the PUC **may be guided** by its finding of accrued and annual depreciation in a prior case or cases, in determining such items in a rate case currently before it, **such prior findings are not res judicata.**”²²⁷

In *Pa. Power*, the Commonwealth Court affirmed a Commission decision which disallowed PPL’s proposed rate increases based upon a determination of “annual depreciation” of PPL’s assets. The Commonwealth Court reasoned that the Commission consistently applied the same reserve requirement study methods and statistics for both accrued and annual depreciation.²²⁸

Importantly, the “reasonably consistent basis” language used by the Commonwealth Court specifically relates to the calculation of accrued depreciation and annual depreciation in determining just and reasonable rates.²²⁹ However, it is not *de facto* authority of a utility’s depreciation procedure for its plant in rate base or a mandate that a utility’s procedure be accepted indefinitely. In other words, merely because a utility used a depreciation procedure in the past is neither a justification nor a limitation for determining what constitutes just and reasonable rates in this proceeding.²³⁰ Instead, both accrued and annual depreciation must be reasonably consistent with each other.²³¹

²²⁶ *Pa. Power* at 158.

²²⁷ *Id.* (emphasis added).

²²⁸ *Id.*

²²⁹ *See Id.*

²³⁰ *See Id.*

²³¹ *Id.*

2. The Public Utility Code and Commission regulations do not prohibit the adoption of the ALG procedure.

The Public Utility Code does not require that a utility's currently utilized depreciation procedure for certain plant must be accepted indefinitely. Importantly, the Public Utility Code provides the following regarding depreciation:

a) Accounts.--Every public utility shall carry on its books or records of account, proper and reasonable sums representing the annual depreciation on its property used or useful in the public service, which sums shall be based upon the average estimated life of each of the several units or classes of depreciable property. The commission, by appropriate order, after hearing, shall, **except where found to be inappropriate**, establish for each class of public utilities, the units of depreciable property, the loss upon the retirement of which shall be charged to the depreciation reserve.

(b) Statements.--Every public utility shall file with the commission, at such times and in such form as the commission may prescribe, statements setting forth the details supporting its computation of annual depreciation, as recorded on the books or records of accounts of the public utility. **If the commission, upon review of such statements, is of the opinion that the amount of annual depreciation so recorded by any public utility is not reasonable and proper, it may, after hearing, require that provision be made for annual depreciation in such sums as may be found by it to be reasonable and proper.** In making its findings, the commission shall give consideration to the experience of the public utility, and the predecessors of the public utility in accumulating depreciation reserves, the retirements actually made, and such other factors as may be deemed relevant.

(c) Use of estimates.--**The commission shall not be bound in rate proceedings to accept, as just and reasonable for rate-making purposes, estimates of annual depreciation** established under the provisions of this section, but in such rate proceedings it shall give consideration to statements submitted under this section, in addition to such other factors as may be relevant.²³²

²³² 66 Pa. C.S. § 1703 (emphasis added).

As shown above, the Public Utility Code does not require that a utility's currently utilized depreciation procedure for certain plant must be accepted indefinitely.

The Commission's regulations provide:

(c) In subsequent ratemaking proceedings, the most recent annual depreciation report or service life study approved or deemed approved for accounting purposes **only** under this chapter, **constitutes a rebuttable presumption** as to the reasonableness of the accrued depreciation claimed for ratemaking purposes, and the burden of proving the unreasonableness of the accrued depreciation shall be on the challenging party.²³³

The purpose of the Commission's regulations regarding annual depreciation reports, service life studies, and capital investments plans is "to establish uniform and industry wide reporting requirements designed to improve the Commission's ability to monitor on a regular basis the depreciation practices and capital planning of electric, telephone, gas and water public utilities subject to Commission jurisdiction."²³⁴

The Commission's regulations must be read in the context of Section 1301(a)'s mandate that all rates be "just and reasonable"²³⁵ and Section 315(a)'s placing of the burden of proof on the utility to establish the justness and reasonableness of every element of a propose rate increase.²³⁶ Additionally, the U.S. Supreme Court stated that the public utility bears the burden of proof regarding operating expenses for depreciation:

The point is as to the necessity for the annual charges for depreciation, as made or claimed by the Company, in order to avoid confiscation through the rates in suit. On that point the Company has the burden of proof. We find that this burden has not been sustained. Nor is the result changed by figuring the allowances at the somewhat reduced amounts fixed by the court below.

²³³ 52 Pa. C.S. § 73.9(c) (emphasis added).

²³⁴ 52 Pa. Code § 73.1

²³⁵ 66 Pa. C.S. § 1301(a).

²³⁶ 66 Pa. C.S. 315(a).

We find this point to be a critical one. The questionable amounts annually charged to operating expenses for depreciation are large enough to destroy any basis for holding that it has been convincingly shown that the reduction in income through the rates in suit would produce confiscation.²³⁷

While the OCA asserts and maintains in this section of this brief that it carried its burden of production to demonstrate that the ALG procedure should be adopted, to the extent Section 73.9(c) of the Commission's regulations is interpreted to shift the burden of proof to the OCA, there is a conflict between regulation and statute, and the statute must control.²³⁸ Simply put, the OCA has presented substantial evidence that Columbia's continued use of ELG results in excessive amounts charged to operating expenses for depreciation and therefore results in unjust and reasonable rates.

D. Substantial record evidence shows that use of the ALG procedure will permit the Company's recovery of reasonable amounts for depreciation expense and permit accumulated depreciation and annual depreciation to be calculated on a reasonably consistent basis but will remove excess amounts from being charged in rates to consumers.

Use of the ALG procedure will permit the Company's recovery of reasonable amounts charged to operating expenses for annual depreciation, as required by *Lindheimer* and *Hope*, but will remove excess amounts from being charged in rates. Specifically, OCA witness Garrett testified that Columbia's depreciation expense balance should be set in the FPFTY at \$84,887,176, in contrast with the Company's claimed depreciation expense

²³⁷ *Lindheimer* at 175.

²³⁸ *Victory Bank v. Commonwealth*, 190 A.3d 782, 783 (Pa. Cmwlth. 2018) ("It is axiomatic that a statute is law and trumps an administrative agency's regulations. In addition, where there is a conflict between a statute and a regulation which purports to implement the statute's provisions the regulation must give way.")

balance of \$130,689,599.²³⁹ The adjustment of \$45,802,423 is to remove the excess amounts charged to operating expense for annual depreciation based on use of the ELG procedure.²⁴⁰

Columbia's claimed depreciation expense under its proposed continued use of the ELG procedure represents approximately **58%** of Columbia's \$110.5 million rate increase request.²⁴¹ OCA witness Garrett testified as follows:

In this case, the difference in the annual depreciation accrual between the ELG and ALG methods alone is \$44 million based on plant balances at the end of the Fully Projected Future Test Year.²⁴²

OCA witness Mugrace testified that a change from ELG to ALG after being grossed up to account for federal and state taxes "reduces the revenue requirement by \$63.615 million."²⁴³

Additionally, through ELG, OCA witness Garrett testified that Columbia Gas of Pennsylvania also unnecessarily increases the depreciation accrual charged to customers by approximately \$1.6m per year as follows:

[T]he ALG method results in a fairer application of depreciation rates compared to the ELG method given the realities of ratemaking proceedings. Mr. Spanos's decision to use the ELG method unnecessarily increases the **annual** depreciation accrual charged to customers by approximately \$1.6 million. In other words, even if no other adjustments are made to the depreciation study except the adoption of the majority view ALG method, it would result in a decrease of \$1.6 million to the Company's proposed annual depreciation accrual.²⁴⁴

²³⁹ OCA St. 3 at 5-6 (Figure 3).

²⁴⁰ \$110.5 million x .58 (58%) = approximately \$64 million.

²⁴¹ OCA St. 2SR at 26; OCA Exh. DM-SR-32.

²⁴² OCA St. 3 at 63.

²⁴³ OCA St. 2SR at 25-26.

²⁴⁴ OCA St. 3 at 66.

Moreover, OCA witness Garrett testified as follows regarding the increased depreciation accrual resulting from Columbia's use of the ELG procedure:

The Company's use of the ELG method, rather than the widely applied ALG method, increases the annual depreciation accrual charged to customers by \$37 million in the 2024 Study, by \$39 million in the 2025 Study, and by \$44 million in the 2026 Study. In other words, even if there are no adjustments to the net salvage rates service life, or other depreciation parameters for any accounts in the depreciation study, using the majority-view ALG method alone will result in significantly fairer rates for customers.²⁴⁵

The magnitude of the unreasonably high amount of depreciation expense Columbia proposes to charge to current ratepayers through Columbia's use of the ELG procedure is immediately apparent and mathematically uncontested. The record evidence demonstrates that Columbia's continued use of ELG results in unjust and unreasonable rates.

Use of the ALG procedure will permit the Company's accumulated depreciation and annual depreciation to be calculated on a reasonably consistent basis, as required by *Pa. Power*. As OCA witness Garrett testified, "the ALG method is used by analysts and adopted by regulators in the vast majority of jurisdiction and in the vast majority of cases".²⁴⁶ Therefore, it is evident that both annual depreciation expense allowance and accrued depreciation are calculated on a reasonably consistent basis.²⁴⁷ Mr. Garrett further testified that "[t]o say otherwise would mean that the vast majority of regulatory jurisdictions (using the ALG method) are authorizing inequitable depreciation rates, have

²⁴⁵ OCA St. 3 at 5.

²⁴⁶ OCA St. 3 at 61.

²⁴⁷ OCA St. 3SR at 14.

and have been doing so for decades, which cannot be accurate.”²⁴⁸ Moreover, requiring Columbia to switch to the ALG procedure also ensures reasonable consistency with Columbia’s current depreciation treatment of pre-1976 plant under the ALG procedure.²⁴⁹

The ALG procedure satisfies this purpose as, compared to ELG, ALG simplifies and improves the Commission’s ability to monitor depreciation practices and capital planning for regulated utilities. Indeed, the ALG procedure results in systematic and rational cost recovery with near-term customer rate relief and full cost recovery of utility investments.²⁵⁰

Under ALG, the depreciation rates are consistent and predictable as the same depreciation rate is used throughout the service life of the account.²⁵¹ For example, OCA witness Garrett testified as follows regarding an example of ALG: “under the ALG procedure, the depreciation rate is 15.625% per year ($1/6.4 = 15.625\%$).”²⁵² Mr. Garrett also testified to the additional complexities of ELG, as follows:

Under the ELG procedure, however, there are higher rates and accrual amounts during the earlier years. In reality, Columbia has numerous units of property that are depreciated on a group basis in each account. Under the ELG procedure, customers rates (not just depreciation rates), would need to be adjusted every year in order for the ELG procedure to produce accurate depreciation rates. Since that is not practical, the vast majority of jurisdictions have adopted the ALG procedure.²⁵³

OCA witness Garrett further testified as follows:

²⁴⁸ OCA St. 3SR at 14.

²⁴⁹ Columbia St. 5-R at 4.

²⁵⁰ OCA St. 3 at 62.

²⁵¹ *See, e.g.*, OCA St. 3 at 64.

²⁵² OCA St. 3 at 13.

²⁵³ OCA St. 3SR at 13-14.

When a utility has made substantial, recent capital investments, depreciation expense calculated under the ELG method will always be higher than the expense calculated under the ALG method. The larger the amount of the investments, the larger the discrepancy will be between the two procedures.²⁵⁴

Columbia witness Spanos argued that “the book reserve on the Company books is only appropriate under the ELG procedure for forecasting the future test years.”²⁵⁵ Book reserve is also known as accumulated depreciation. While Columbia witness Spanos claimed in rebuttal that OCA witness Garrett made an error by using the incorrect reserve balance in calculating the proposed rates under ELG, OCA witness Garrett testified as follows:

Q. Mr. Spanos claims that you made an error by using the incorrect reserve balances in calculating your proposed rates under the ELG method. What is your response?

A. To calculate my proposed depreciation rates, I used the reserve balances that were presented in Mr. Spanos’s exhibits. If Mr. Spanos is suggesting different reserve balances should be used, he did not present those balances to be considered. The primary issue before the Commission is whether the ALG or ELG method should be used, which has an impact of approximately \$45 million to depreciation expense as of the 2026 depreciation study. The use of different estimated reserve balances, as Mr. Spanos is suggesting, should not have a material impact to the overall result. If it does, the Company can present what it believes are the correct balances to use for calculating ALG rates so the parties can review it (though it did not take the opportunity to do so in rebuttal testimony).²⁵⁶

Based on Mr. Garrett’s recommended adjustment, OCA witness Mugrace made a corresponding reduction to Columbia’s claimed accumulated depreciation of

²⁵⁴ OCA St. 3 at 62-63.

²⁵⁵ Columbia St. 5-R at 14.

²⁵⁶ OCA St. 3SR at 14-15.

\$45,802,423.²⁵⁷ While the Company disagreed with the basis of Mr. Mugrace's adjustment, it did not present evidence indicating that the proposed adjustment was inaccurate.²⁵⁸ As a result, if the Commission adopts the OCA's recommended adjustment to depreciation expense, Mr. Mugrace's adjustment to accumulated depreciation should be adopted as well.

In rejoinder, once it was too late for OCA witnesses Garrett or Mugrace to respond, Columbia witness Spanos stated as follows:

OCA Witness Garrett has stated he utilized the same book reserve that was developed in the Depreciation Studies. However, if he utilized the ALG procedure then the book reserve he utilizes in his calculations would be different than that of the Depreciation Studies. In each case, the book reserve would be lower and the resulting depreciation expense that he calculates would be higher. Therefore, it is OCA Witness Garrett's responsibility to calculate the proper book reserve for his calculations.²⁵⁹

To be clear, the OCA is not the party that produced or was required to produce a depreciation study for the FFPTY as it does not bear the burden of proof in this case. Columbia produced the depreciation study to meet its initial burden of proof. When the burden of production shifted, the OCA only needed to demonstrate, per *Lindheimer* and *Hope*, that the ELG procedure for determining annual depreciation expense is unreasonable and that the ALG procedure is reasonable to ensure the Company is whole and the integrity of its investments maintained, which the OCA has successfully demonstrated. The OCA also needed to demonstrate, per *Pa. Power*, that the use of the ALG procedure will permit

²⁵⁷ OCA St. 2 at 10; OCA Exh. DM-SR-6.

²⁵⁸ Columbia St. 5-5 at 32.

²⁵⁹ OCA St. 5RJ at 7.

accumulated depreciation (or book reserves) and annual depreciation expense to be calculated on a reasonably consistent basis, which the OCA also has successfully demonstrated. Columbia's tactics in rejoinder to refuse to calculate the book reserve or accumulated depreciation amounts under the ALG procedure should be viewed as an impermissible shift of the burden of proof to a challenger of proposed rates. If this is permitted, it is questionable whether any party can sustain a challenge to depreciation expense without having to produce a separate depreciation study that would increase expense and burden, including the discovery burden.

E. Substantial record evidence shows that the use of ELG depreciation unreasonably accelerates recovery of depreciation expense.

OCA witness Garrett testified that the depreciation rates calculated under the ELG procedure results in higher depreciation rates in early years relative to later years.²⁶⁰

The Commission already acknowledged that ELG, compared to other depreciation procedures, accelerates recovery as follows:

An account can be divided on a vintage basis, which is simply a grouping of assets by the year in which they were put in service. A vintage can be further subdivided by the ages which different groups of assets in the vintage will probably attain. The equal life group ("ELG") method assumes, for a given estimated life of a mass group and a given vintage that: a certain percentage of the assets will be retired in the first year and should be depreciated 100% in that first year; another percentage of the assets will be retired in the second year and should be depreciated 50% in the first year; another percentage will retire in the third year and should depreciated 33% in the first year, etc. **The practical effect of ELG as contrasted with other methods is to accelerate the recovery of capital.**²⁶¹

²⁶⁰ OCA St. 3 at 61.

²⁶¹ *Pa. PUC v. Philadelphia Suburban Water Company*, 1986 Pa. PUC LEXIS 118, *14-15 (emphasis added).

As OCA witness Garrett testified, this fact is confirmed by authoritative depreciation literature as follows:

When contrasted with the average life procedure, the equal life group procedure results in annual accruals that are **higher during the early years** and lower in the later years.²⁶²

The NARUC Public Utility Depreciation Practices literature comes to the same conclusion about ELG:

[T]he ELG method results in annual accruals that are **higher during the early years** of a vintage's life, thereby causing an increase in depreciation expense and revenue requirements during these years.²⁶³

In fact, as illustrated in this proceeding, the use of ALG instead of ELG results in a \$44 million difference in expense amounts between the two procedures and an approximately \$63.615 million difference in revenue requirement.²⁶⁴ OCA witness Garrett testified as follows:

In order for the ELG method to be properly applied, a utility would need to revise depreciation each year. When a utility has made substantial, recent capital investments, depreciation expense calculated under the ELG method will always be higher than the expense calculated under the ALG method. The larger the amount of the investments, the larger the discrepancy will be between the two procedures...In this case, the difference in the annual depreciation accrual between the ELG and ALG methods alone is \$44 million based on plant balances at the end of the Fully Projected Future Test Year which is December 31, 2025.²⁶⁵

²⁶² OCA St. 3 at 61 *citing* Wolf & W. Chester Fitch, *Depreciation Systems* at 93 (Iowa State University Press, 1994) (emphasis added).

²⁶³ OCA St. 3 at 61 *citing* National Association of Regulatory Utility Commissioners *Public Utility Depreciation Practices* at 176 (NARUC 1996)(emphasis added).

²⁶⁴ OCA St. 3 at 63; OCA St. 2SR at 25-26.

²⁶⁵ OCA St. 3 at 62-63.

OCA witness Garrett provided the following example showing how ELG results in higher depreciation rates in earlier years relative to ALG:

For the following illustration, assume a group of property containing two units, one with an original cost of \$4,000 and a 4-year life and the second with an original cost of \$6,000 and an 8-year life. Thus, the average life of this group is 6.4 years. Under the ALG method, the depreciation rate is 15.625% per year ($1/6.4 = 15.625\%$). The following table illustrates this example.

Figure 1
ALG Procedure

Year	Balance	Retired	Rate	Annual Accrual	Accum. Deprec.
1974	10000		15.625%	1563	0
1975	10000		15.625%	1563	1563
1976	10000		15.625%	1563	3125
1977	10000	4000	15.625%	1563	4688
1978	6000		15.625%	938	2250
1979	6000		15.625%	938	3188
1980	6000		15.625%	938	4125
1981	6000	6000	15.625%	938	5063
1982	0				0

As shown in the annual accrual column above, the full \$10,000 is depreciated after eight years. Now, considering the same assumptions presented above, the following tables illustrate the same scenario except that the rate is calculated under the ELG method.

Figure 2
ELG Procedure

Year	Balance	Retired	Rate	Annual Accrual	Accum. Deprec.
1974	10000		17.50%	1750	0
1975	10000		17.50%	1750	1750
1976	10000		17.50%	1750	3500
1977	10000	4000	17.50%	1750	5250
1978	6000		12.50%	750	3000
1979	6000		12.50%	750	3750
1980	6000		12.50%	750	4500
1981	6000	6000	12.50%	750	5250
1982	0				0

As with the ALG example presented above, the full \$10,000 investment is still fully depreciated after eight years. However, there are higher rates and accrual amounts during the earlier years. The reason there is a 17.5% depreciation rate instead of a 15.625% depreciation rate in the early years is because the two units in this group are treated separately under the ELG method. The following table shows how the rates in this example are calculated.

Figure 3
ELG Rate Development

Group	Group Amount	Group Life	Group Rate	Annual Accrual	
				1974-77	1978-81
A	4000	4	25.00%	1000	
B	6000	8	12.50%	750	750
Annual accruals				1750	750
Balance during interval				10000	6000
Annual accrual rate %				17.50%	12.50%

This example is simplified in an attempt to explain the complexities of the ELG method. In this example, the higher rate of 17.5% stayed the same for four years because there are only two units in this simple example, and the rate drops to 12.5% after the first unit retires.²⁶⁶

²⁶⁶ OCA St. 3 at 65-66 (internal citations omitted).

Under the ALG procedure example presented above, the average life of the group was 6.4 years, which under the ALG procedure means that the depreciation rate is 15.625%²⁶⁷ per year while the ELG depreciation rate fluctuates significantly.²⁶⁸ As such, ALG simplifies and improves the Commission's ability to monitor depreciation practices and capital planning for regulated utilities compared to ELG.

As further shown in the above example, the ELG procedure results in higher depreciation expense for current ratepayers compared to the ALG procedure.²⁶⁹ Indeed, Columbia witness Spanos provided an example in rebuttal testimony that provides further evidence that ELG leads to higher depreciation rate in early years, as Mr. Spanos shows \$266.67 of depreciation expense under ELG vs. \$200 in depreciation expense under ALG for each year for the first five years.²⁷⁰ Substantial evidence shows that ELG results in accelerated depreciation.

F. Substantial record evidence shows that the use of ELG procedure is inconsistent with the well-established “matching principle” of ratemaking.

The well-established “matching principle” of ratemaking requires that expenses, revenue, and rate base match over the same time period.²⁷¹ For example, if post-test year additions to expenses and revenues are allowed, “the balance established by the test year

²⁶⁷ $(1/6.4 = 15.625\%)$.

²⁶⁸ OCA St. 3 at 65-66; OCA St. 3SR at 13.

²⁶⁹ OCA St. 3 at 65-66.

²⁷⁰ OCA St. 3SR at 13-14; Columbia St. 5-R at 6-7.

²⁷¹ *Pa. PUC v. NFGD*, 1994 Pa. PUC LEXIS 135, *13 (Oct. 7, 1994)(*NFGD*).

is lost and the matching principle is violated.”²⁷² Two basic principles of public utility ratemaking are that: 1) a public utility only earns money from its rate base and 2) a public utility does not earn money on its expenses.²⁷³ “A utility is not permitted to pad its estimates of annual depreciation so as to meet unknown contingencies, or to compensate for possible future errors in judgment.”²⁷⁴

While depreciation mechanics should correct depreciation overcharges over the life of a utility’s plant investment, since utilities have constantly growing plant in service, compared to the ALG procedure, the choice to use the ELG procedure results in higher depreciation rates for current customers.²⁷⁵ OCA witness Garrett testified that, “[t]he larger the amount of the investments, the larger the discrepancy will be between the two procedures.”²⁷⁶

Under ELG, annual depreciation expense is accelerated relative to accrued depreciation. As such, the depreciation reserve grows disproportionately fast in earlier years, producing mismatches between revenues and expenses.²⁷⁷ ALG, by contrast, keeps annual depreciation expense proportional to the depreciation reserve buildup and properly

²⁷² *Id.*; see also *Re. Niagra Mohawk Power Co.*, 1986 N.Y. PUC LEXIS 3, *97 (Dec. 19, 1986)(a plant running for 50 years but packing all of its depreciation accruals into the first 40 years would violate generational equity and the matching principle).

²⁷³ *Pa. Power* at 159.

²⁷⁴ *Pa. Power* at 157.

²⁷⁵ OCA St. 3SR at 13; see also *Lindheimer* at 154 (“though the calculations are mathematical, the underlying predictions of life of plant and salvage are essentially matters of opinion...opportunities for excessive allowances for depreciation, even under a correct system of accounting, are always present.”).

²⁷⁶ OCA St. 3 at 62-63.

²⁷⁷ OCA St. 3 at 63.

matches revenues and expenses.²⁷⁸ ALG results in a reasonably consistent annual depreciation expense relative to accrued depreciation, while ELG creates a mismatch between revenues, expenses, and rate base in violation of the matching principle.

G. Substantial record evidence shows that the ELG procedure results in intergenerational inequity among consumers paying utility rates.

Columbia's use of the ELG procedure results in intergenerational inequity. As stated in *Re Minnegasco, Inc.* "[a]s a general rule, it is inequitable and economical [sic] unsound to ask one 'generation' of captive ratepayers to bear the cost of providing service to another."²⁷⁹ Simply put, Columbia's current ratepayers should not be required to pay accelerated depreciation costs for the potential that years from now those rates may be lower to future customers, who may or may not be the same customers paying accelerated rates now. Moreover, Section 1304 of the Public Utility Code, which prohibits discrimination in rates, provides:

Section 1304. Discrimination in rates.

No public utility shall, as to rates, make or grant any unreasonable preference or advantage to any person, corporation, or municipal corporation, or subject any person, corporation, or municipal corporation to any unreasonable prejudice or disadvantage. No public utility shall establish or maintain any unreasonable difference as to rates, either as between localities or as between classes of service.²⁸⁰

²⁷⁸ *Id.*

²⁷⁹ *Re Minnegasco, Inc.*, 143 PUR4th 419, 426 (May 3, 1993)(*Re Minnegasco* is not available on LEXIS so the OCA has appended the case in full to this brief as Appendix D); *see also Re Limerick Nuclear Generating Station*, 1982 Pa. PUC LEXIS 102, *65 Order (May 7, 1982).

²⁸⁰ 66 Pa. C.S. § 1304.

Consistent with Section 1304, Columbia's current customers are being unreasonably disadvantaged because they are subject to Columbia's preferred ELG depreciation method. Consumers, on their own, cannot readily negotiate with a utility and must "rely upon" the Commission to provide "a complete, permanent, and effective bond of protection from excessive rates and charges" of the public utility.²⁸¹ The Commission's "responsibilities include the protection of future, as well as present, consumer interests."²⁸²

The ELG procedure is an accelerated form of depreciation, which causes current customers to pay greater depreciation expense than future customers for the same level of utility service, resulting in intergenerational inequity.²⁸³ While Columbia witness Spanos claimed that the ALJ procedure results in higher rates over time and intergenerational inequity, OCA witness Garrett responded as follows:

I do not agree with Mr. Spanos's narrative on these issues. Again, Mr. Spanos is attempting to position himself as a representative not only for customers, but very specifically for future customers. In reality, the Company's proposal to use the ELG method results in higher cash flow for the Company in the present, which is likely the primary motivation for the Company's proposal to use the ELG method. From my point of view, it is the ELG method, not the ALG method, that results in intergenerational inequity for customers. To say otherwise would mean that the vast majority of regulatory jurisdictions (using the ALG method) are authorizing inequitable depreciation rates, and have been doing so for decades, which cannot be accurate.²⁸⁴

²⁸¹ *Permian Basin Area Rate Cases*, 390 U.S. 747, 794-95 (1968) (*Permian Basin*) (citing *Atlantic Ref. Co. v. Pub. Serv. Comm'n*, 360 U.S. 378, 388 (1981)).

²⁸² *Permian Basin*, 390 U.S. at 797.

²⁸³ See *Re Limerick Nuclear Generating Station*, 1982 Pa. PUC LEXIS 102, *65 Order (May 7, 1982) ("Intergenerational inequities -- Current consumers should not pay for a plant from which they may not be around to benefit.")

²⁸⁴ OCA St. 3SR at 14.

Columbia's continued use of the ELG procedure deprives current customers of a \$63.615 million revenue requirement decrease that they would experience for the same plant under the ALG procedure.²⁸⁵ Additionally, the ALG procedure equitably spreads the annual depreciation expense on rate base investment over the generations of customers that receive service from the investments (i.e., favors intergenerational equity).²⁸⁶ Conversely, the ELG procedure assigns more depreciation expense to customers that take service early in the asset's service life and reduces the expense to customers toward the end of the asset's service life, which directly results in intergenerational inequity and discrimination in rates.²⁸⁷

Columbia witness Spanos did not rebut the fact that current customers will pay more for Columbia's assets relative to future customers under the ELG procedure. OCA witness Garrett testified:

Furthermore, I do not believe the financial well being of future customers is the primary motivation for the Company's proposal to use the ELG method. Mr. Spanos does not represent either present or future customers in this case, and he exclusively represents utility companies as I understand. Also, in Mr. Spanos's rebuttal testimony, I did not see him rebut the fact that compared with the ALG procedure, the ELG procedure will result in higher depreciation rates for current customers. Likewise, the ELG procedure will result in higher cash flows for Columbia relative to the ALG procedure.²⁸⁸

OCA witness Garrett further testified as follows:

²⁸⁵ OCA St. 2SR at 25-26.

²⁸⁶ OCA St. 3SR at 13.

²⁸⁷ OCA St. 3SR at 13.

²⁸⁸ OCA St. 3SR at 13.

Q. Did Mr. Spanos rebut the fact that current customers would pay more for the Company's assets relative to future customers under the ELG procedure?

A. No. This point is undisputable and is proven mathematically in both Mr. Spanos's testimony and my testimony. Under the ELG procedure proposed by Mr. Spanos (in this jurisdiction), current customers would effectively be subsidizing future customers by paying a larger proportionate share of what is essentially the same asset base.²⁸⁹

OCA witness Garrett testified that "[u]nder the ELG procedure, there are higher rates and accrual amounts during the earlier years."²⁹⁰ OCA witness further Garrett testified that "[i]n reality, Columbia has numerous units of property that are depreciated on a group basis in each account."²⁹¹ OCA witness Garrett further testified as follows:

Under the ELG procedure, customer rates (not only depreciation rates) need to be adjusted every year in order for the ELG procedure to produce accurate depreciation. Since that is not practical, the vast majority of jurisdictions have adopted the ALG procedure.²⁹²

As the ALG procedure simplifies the Commission's ability to monitor depreciation practices and capital planning for regulated utilities, it furthers the Commission's regulations regarding depreciation "to establish uniform and industry-wide reporting requirements designed to improve the Commission's ability to monitor on a regular basis the depreciation practices and capital planning of electric, telephone, gas and water public utilities subject to Commission jurisdiction."²⁹³

²⁸⁹ OCA St. 3SR at 13.

²⁹⁰ OCA St. 3SR at 13.

²⁹¹ OCA St. 3SR at 15.

²⁹² OCA St. 3SR at 13-14.

²⁹³ 52 Pa. C.S. § 73.1.

H. A super majority of state commissions approve the ALG procedure and Pennsylvania is in the small minority of jurisdictions that approve the ELG procedure.

Given ELG's practical effect of accelerated depreciation recovery from ratepayers, OCA witness Garrett testified that "the ALG procedure is used by analysts and adopted by regulators in the vast majority of jurisdictions in the vast majority of cases."²⁹⁴ OCA witness Garrett further testified that Columbia witness Spanos recommends using the ALG procedure in the vast majority of cases he appears in, including in all Columbia Gas proceedings in other jurisdictions, but for Columbia Gas of Pennsylvania, as follows:

In reading Mr. Spanos's testimony, one could get the impression that Mr. Spanos himself does not also use the ALG in most of the depreciation studies that he conducts. However, based on my experience, Mr. Spanos utilizes the ALG method in the vast majority of depreciation studies I have reviewed that have been sponsored by him and Gannett Fleming. This fact alone should negate any of Mr. Spanos's statements or inferences in his rebuttal testimony suggesting the ALG procedure might not be fair, accurate, or reasonable. In other words, his claim in this case that the ELG procedure is "more equitable" would necessarily mean that he is using a *less* equitable procedure in his depreciation studies in other jurisdictions. In reality, the ALG procedure that Mr. Spanos uses a majority of the time is very fair and reasonable (assuming reasonable estimates are made for other depreciation parameters). Furthermore, I do not believe the financial well being of future customers is the primary motivation for the Company's proposal to use the ELG method. Mr. Spanos does not represent either present or future customers in this case, and he exclusively represents utility companies as I understand.²⁹⁵

Moreover, under cross-examination, Mr. Spanos was unable to state whether more than ten states in the country use the ELG procedure for natural gas distribution

²⁹⁴ OCA St. 3 at 61.

²⁹⁵ OCA St. 3 at 62; *see also* Tr. 320-341; OCA Cross Exh. 1-2, 4-5.

companies.²⁹⁶ Instead, Mr. Spanos stated “[t]here are more states that use average service life [also referred to as ALG] than equal life group today.”²⁹⁷ Columbia witness Spanos noted that the ELG procedure is used by the Texas Railroad Commission, the Federal Communications Commission, Alabama, Oregon, and Colorado.²⁹⁸ Mr. Spanos also claimed that New York is “considering ELG for similar reasons in an active case in New York.”²⁹⁹ However, the active case that Mr. Spanos refers to in which a switch from ALG to ELG was proposed resulted in a settlement which did not include a switch from ALG to ELG.³⁰⁰

There are multiple examples of regulatory commissions moving away from the ELG procedure in favor of the ALG procedure. In Duke Energy Indiana’s (Duke Indiana) 2020 base rate case, Duke proposed using the ELG procedure, which had been adopted by the Indiana commission in previous cases.³⁰¹ The Indiana Utility Regulatory Commission found that the ELG procedure resulted in unreasonable rates as follows:

First, with respect to the question of whether the ELG or ALG method should be used, we find the evidence presented by OUCC witness Mr. Garrett and Industrial Group witness Mr. Andrews persuasive, as both witnesses showed that the ELG method results in unreasonably high depreciation rates. ALG depreciation rates result in systematical and rational cost recovery with near

²⁹⁶ Tr. 352-353.

²⁹⁷ Tr. 330.

²⁹⁸ Columbia St. 5-R at 12-13; Tr. 351.

²⁹⁹ Columbia St. 5-R at 13.

³⁰⁰ *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagra Mohawk Power Corporation d/b/a National Grid for Gas Service*, Case No. 24-G-0323, Order at 17-22 (Aug. 14, 2025); *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagra Mohawk Power Corporation d/b/a National Grid for Gas Service*, Case No. 24-E-0322, Order at 17-22 (Aug. 14, 2025).

³⁰¹ OCA St. 3 at 62.

term customer rate relief and full cost recovery of utility investments. While we have determined in the past that the ELG methodology was appropriate and acknowledge the weight given to precedent in many prior decisions, we always evaluate each case as it comes before us and do not need to approve the same methodology based on prior decisions, especially in light of a changed landscape. The use of ELG in a higher than average investment cycle has the effect of unnecessarily increasing the near term depreciation expense as compared to the use of ALG.³⁰²

OCA witness Garrett testified that “[t]he Indiana commission’s criticism of the ELG method would also apply here.”³⁰³

Similarly, the Kentucky Public Service Commission found that the ELG procedure front-loads depreciation expense in earlier years and decreases it in later years, resulting in a mismatch between revenues and expenses. The Kentucky PSC stated as follows:

Duke Kentucky proposes, as part of developing its depreciation rates, continued use of the ELG procedure. The Attorney General recommends the Commission adopt the ALG procedure in developing Duke Kentucky's depreciation rates. The Attorney General contends that the ALG methodology is the predominant method that is used in the electric industry for developing depreciation rates. The Attorney General contends that, under the ELG methodology, the capital recovery periods are accelerated and shortened and, thus, the depreciation rates are greater than if the ALG procedure was used. The Attorney General argues that the ALG procedure is as accurate as the ELG procedure and the ALG procedure smooths the data so that the depreciation rates for the group of assets tend to remain constant. Use of the ALG procedure will result in a decrease in Duke Kentucky's depreciation expense of \$6.920 million.

Duke Kentucky requested an increase in depreciation expense of \$6.920 million, based on its request to utilize the ELG procedure for computing depreciation rates. As was discussed in the rate base section of this Order, this Commission has found that the ELG procedure does not accurately match revenues and expenses, is front-loaded, and Duke Kentucky is the only Kentucky based utility that utilizes the ELG procedure for computing depreciation rates.

³⁰² OCA St. 3 at 62 citing *Petition of Duke Energy Indiana, LLC.*, Cause No. 45253, Order at 90 (June 29, 2020).

³⁰³ OCA St. 3 at 63.

Regulatory accounting requires the proper matching of revenues and expense in order to produce fair, just and reasonable rates. The Commission finds Duke Kentucky's proposed ELG procedure does not meet that criteria and that Duke Kentucky's depreciation expense should be reduced by \$6.920 million.³⁰⁴

Similar to *Duke Kentucky*, Columbia's proposed ELG procedure does not properly match revenues to expenses in order to produce just and reasonable rates. Importantly, the Kentucky Public Service Commission found that Duke Kentucky's continued use of the ELG procedure resulted in unjust and unreasonable rates due to a \$6.920 million difference to Duke Kentucky's depreciation expense balance between using ALG instead of ELG. *Id.* For Columbia Gas of Pennsylvania, the difference between using ALG and ELG for Columbia's depreciation expense balance is 6.6 times higher, or 566% higher than Duke Kentucky's depreciation expense balance compared to Columbia's \$45,802,423 depreciation expense balance.³⁰⁵ This further illustrates the exorbitantly unjust and unreasonable rates that are the result of Columbia's choice to continue using the ELG procedure.

I. Conclusion – Substantial evidence demonstrates that Columbia's proposal to continue using the ELG depreciation procedure results in unjust and unreasonable rates.

Columbia's continued use of the ELG procedure imposes an unjustified and unreasonable \$63.615 million revenue requirement burden on ratepayers, inflates the

³⁰⁴ OCA St. 3 at 63-64 *citing Application of Duke Energy Kentucky, Inc.*, Case No. 2017-00321, Order at 26-27 (Apr. 13, 2018) (*Duke Kentucky*).

³⁰⁵ OCA St. 2-SR at 25.

depreciation expense balance by approximately \$45 million, and represents approximately 58% of Columbia's revenue requirement increase request.³⁰⁶

The Commission has the legal authority to protect ratepayers from unjustified rate increase proposals, including Columbia witness Spanos' proposal to use the ELG procedure solely for the Columbia Gas utility operating in the Commonwealth of Pennsylvania.³⁰⁷ Continued use of ELG is not required by law or regulation.³⁰⁸

Substantial record evidence demonstrates that the ALG procedure produces just and reasonable rates while the ELG procedure is a form of accelerated depreciation.³⁰⁹ OCA witness Garrett's depreciation rates were calculated using the same service life parameters proposed in Columbia's depreciation study.³¹⁰ No service life adjustments were recommended by OCA witness Garrett.³¹¹ The only difference is that OCA witness Garrett uses the ALG procedure while Columbia witness Spanos uses the ELG procedure.³¹²

Requiring Columbia to switch to the ALG procedure ensures reasonable consistency between annual depreciation and accrued depreciation, is consistent with Columbia's treatment of pre-1976 plant under the ALG procedure, and is also consistent with all other Columbia Gas companies in other jurisdictions, all of which use the ALG procedure. As the ALG procedure results in a just and reasonable application of depreciation rates

³⁰⁶ OCA St. 2SR at 26.

³⁰⁷ See Sections VI.B; VI.E.

³⁰⁸ See Section VI.B.

³⁰⁹ See Section VI.C.

³¹⁰ OCA St. 3 at 69.

³¹¹ OCA St. 3 at 69.

³¹² OCA St. 3 at 69.

compared to the ELG procedure given the realities of ratemaking, the Commission should adopt OCA witness Garrett's depreciation rates, which were calculated using the ALG procedure.³¹³

The ELG procedure distorts the relationship between annual and accrued depreciation by accelerating depreciation expense recovery in earlier years of an asset's service life, which promotes intergenerational inequity.³¹⁴ This front-loading results in an accelerated accumulation of accrued depreciation expense, which is contrary to the requirement that annual depreciation and accrued depreciation be calculated on a reasonably consistent basis and is in violation of the matching principle.³¹⁵ By contrast, the ALG procedure aligns annual depreciation with accrued depreciation in a predictable and consistent basis, ensuring fairness across customer generations and consistency in ratemaking.³¹⁶ The ALG procedure is in accordance with the matching principle, ensures intergenerational equity, and results in just and reasonable rates.³¹⁷

Rejecting Columbia's proposal to continue using ELG is not only legally sound, it is essential in preventing the systematic overcharging of current customers due to Columbia's choice of depreciation procedure for years to come. As such, the Commission should reject Columbia's proposed use of the ELG depreciation procedure in this

³¹³ OCA St. 3 at 66.

³¹⁴ See Section VI.E.

³¹⁵ See Section VI.D.

³¹⁶ See Section VI.B.

³¹⁷ See Sections VI.D-VI-E.

proceeding and instead require Columbia to use the ALG procedure in order to produce just, reasonable, and non-discriminatory rates.

VII. O&M AND A&G EXPENSES

Based on the OCA's analysis discussed below, the Company's claims for operations and maintenance (O&M) and administrative and general (A&G) expenses are inflated, largely unsupported by evidence as being known and measurable, and/or do not result in ratepayer benefit. Mr. Mugrace proposed several adjustments to the Company's projected operating expense levels. These adjustments are as follows:

OCA Recommended Expense Adjustments³¹⁸

Labor Vacancy	\$ (1,698,622)
Incentive Compensation	\$ (2,552,612)
Employee Benefits	\$ (390,741)
Outside Services	\$ (1,436,907)
Corporate Insurance	\$ (131,774)
Injury & Damages	\$ (51,257)
Employee Expenses	\$ (34,245)
Company Memberships	\$ (253,872)
Utilities and Fuel	\$ 28,758
Advertising	\$ 11,365
Materials and Supplies	\$ (558,615)
NCSC Charges	\$ (7,669,076)
DEI Costs	\$ (130,450)
Rate Case Expenses	\$ (182,207)
Uncollectible Expense	\$ (1,487,431)
Rider USP	\$ (220,000)
Total Adjustments to O&M and A&G Expenses	\$ (16,757,680)

The adjustments to O&M and A&G expenses identified by OCA witness Mugrace should be disallowed because they are not properly includable in a utility's revenue requirement.³¹⁹

A. Inflation Adjustments

As discussed in Section IV.A, the OCA recommends that the Company's requested inflation adjustments, including the use of historical averaging to determine future expenses, be disallowed.

³¹⁸ OCA Exh. DM-SR-9.

³¹⁹ *Phila. Elec. Co. v. Pa. PUC*, 552 A.2d 342, 346 (Pa. Cmwlth. 1989) ("the PUC is empowered to disallow expenses of a utility that it concludes are of no direct benefit to ratepayers").

The Commission should reject all claimed expense increases that are not supported by targeted or specific data demonstrating increases to each claimed expense.³²⁰ Blanket inflation adjustments, such as the ones proposed by Columbia in its filing, were recently disallowed by the Commission in *PGW 2023*.³²¹ In *PGW 2023*, the Commission rejected PGW’s request to apply a blanket 4.63% inflation adjustment to 20% of its expenses because it was applied broadly and did not meet the “‘known and measurable’ standard for increasing each FTY expense claim in the FPFTY.”³²² In *Wellsboro 2020*,³²³ the Commission determined that the utility bears the burden of proving that its inflationary adjustments represent known and measurable changes to costs over time and that all adjusts to expense claims “directly relate[] to the actual costs expected to be incurred in each expense account in the FPFTY.”³²⁴

Columbia should not be permitted to recover expense increases that it has not demonstrated are known and measurable.³²⁵ Inflation adjustments, including those premised on historical averages of the costs experienced by the utility, are rife with uncertainty and speculative guess work as opposed to one that is bounded by reasonable projections. As stated by OCA witness Mugrace:

I believe including inflation/deflation types factors to adjust for costs are not reasonable because these types of increase adjustments are not known and

³²⁰ *Aqua 2022* at *50-51.

³²¹ *Pa. PUC v. Phila. Gas Works*, Docket No. R-2023-3037933 (Order entered Nov. 9, 2023) (*PGW 2023*) at 72.

³²² *Pa. PUC v. Wellsboro Electric Co.*, R-2019-3008208 (Order entered Apr. 29, 2020) (*Wellsboro 2020*).

³²³ *Wellsboro 2020* at 40.

³²⁴ *Wellsboro 2020* at 40.

³²⁵ 66 Pa. C.S. § 315(e).

measurable and they do not reflect the true costs of providing service. These types of costs are basically blanket type increases/decreases which do not directly relate to actual costs expected to be incurred by the Company in the period for which rates are to be set. Costs should be predicated on evidence or documentation that supports the Company's proposed ratemaking adjustments. Costs should not be adjusted based upon a blanket type of increase and applied to all costs.³²⁶

The Commission should fundamentally reject the notion that merely because costs have increased in the past and inflation exists is sufficient substantiation of Columbia's claims. The OCA's specific expense adjustments, which remove Columbia's inflation adjustments, should be adopted and are discussed in more detail *infra*.

B. Labor

Columbia proposes to increase its labor expenses to \$38,770,674.³²⁷ Columbia had an actual employee count of 728 as of the month ending November 30, 2025. However, Columbia also indicated that it had 715 employees in the historic test year and that Columbia uses the same level of employee headcount in the FTY and FPFTY period.³²⁸ As such, Columbia had a reduction of 13 employees from the November 30, 2023 period.³²⁹ Columbia indicated that it had the following employee vacancies from 2021 through 2024:

³²⁶ OCA St. 2 at 25.

³²⁷ *Id.* at 16.

³²⁸ *Id.*

³²⁹ *Id.*

2021	60	(December 2021)
2022	57	(year-end)
2023	64	(year-end)
2024	65	(year-end) ³³⁰

Utilizing the above vacancy levels for 2022-2024, a three-year average, computes to 62 average employee vacancies per year.³³¹ Applying the Company's 50.57% (O&M percentage) results in an average net vacancy of 31 employees.³³²

Using an accurate vacancy rate ratio for Columbia's labor expense balance ensures that ratepayers are not paying for vacant positions at the Company, as explained by OCA witness Mugrace:

In all organizations there will always be a certain level of vacancies that will not be filled out at any given point in time. This is inherent in all companies and is a natural order of business. Given that, throughout a typical calendar period, the number of employees vary due to retirement, termination, layoffs and management policies. The Company's prior level of vacancy levels show that in the past, a number of vacancies were present. The number or level of employees is determined based upon the need to perform the work assignments, the level of productivity needed to be achieved and the areas in which staff levels appear to be over or under worked and the replacement of employees who are underperforming. Absent a vacancy rate ratio to adjust employee count in the FPFTY period, there could be a situation that arises in which the Company could over-earn in the event no additional employees were to be hired in the test year period.³³³

³³⁰ *Id.* at 17.

³³¹ *Id.*

³³² *Id.*

³³³ *Id.* at 17-18.

OCA witness Mugrace took Columbia's average level of employees as represented by Columbia to reach a four-year average of 715.³³⁴ Next, OCA witness Mugrace divided the average historic vacancy rate of 31 employees by the three-year average of 715 employees, which resulted in a ratio of 4.3812%.³³⁵ Mr. Mugrace took this 4.3812% and multiplied that ratio by the Company's proposed labor balance of \$38,770,674 to arrive at an adjustment of \$1,698,606.³³⁶

The Commission has previously accepted OCA adjustments premised on the use of a vacancy rate ratio.³³⁷ The Commission disfavors speculative estimates of spending. For example, the Commission found, "the parties have correctly cited our precedent for the proposition that a speculative estimates, based on estimated totals of future costs, are not a preferred method for billing future expenses."³³⁸

Columbia's forecast is unreasonable and unsupported by the historic data relevant to employee complement. Columbia did not provide sufficient evidence to establish that it will experience a vacancy rate of less than 4.3182% by the end of the FPFTY and provided no basis upon which the Commission could determine that Columbia will have 0% vacancy. In fact, Columbia's prior vacancy levels show that in the past, a number of vacancies were present.³³⁹ OCA witness Mugrace testified:

The number or level of employees is determined based upon the need to perform the work assignments, the level of productivity needed to be

³³⁴ *Id.* at 17.

³³⁵ *Id.*

³³⁶ *Id.*; OCA Exh. DM-SR-10.

³³⁷ *See, e.g., PGW 2023* at 59.

³³⁸ *Pa. PUC v. Pa. Power & Light Co.*, 85 Pa. PUC 306 at 115 (1995).

³³⁹ OCA St. 2 at 17.

achieved and the areas in which staff levels appear to be over or under worked and the replacement of employees who are underperforming. Absent a vacancy rate ratio to adjust employee count in the FPFTY period, there could be a situation that arises in which the Company could over-earn in the event no additional employees were to be hired in the test year period.³⁴⁰

While the Company claims that its labor expense claim is based on its actual number of filled positions at the end of the HTY and already excludes vacant positions, the Company's position assumes that its number of filled positions will remain the same.³⁴¹

The vacancy rate ratio applied by Mr. Mugrace does not assume that the number of filled positions at the end of the FPFTY will be the same as at the end of the HTY; rather, OCA witness Mugrace's vacancy rate ratio controls for fluctuations in the number of employees by projecting a similar level of employment through the end of the FPFTY as has been experienced by the Company over the last three years.³⁴² OCA witness Mugrace is correct in basing employee expense on actual historic data. OCA witness Mugrace's vacancy rate ratio results in a \$1,698,606 adjustment to labor expense.³⁴³ This adjustment reduces the revenue requirement, including the flow through of taxes, by approximately \$2.359m.³⁴⁴

C. Incentive Compensation

Columbia proposes to include \$2,568,807 in total incentive compensation for the FPFTY period.³⁴⁵ Columbia's incentive compensation plan contains the following performance measures and weightings as follows:

³⁴⁰ *Id.* at 17-18.

³⁴¹ OCA St. 2SR at 10.

³⁴² *Id.* at 10-11.

³⁴³ *Id.* at 11; OCA Exh. DM-SR-10.

³⁴⁴ *Id.*

³⁴⁵ OCA St. 2 at 18.

Financial – adjusted earnings per share	70%
Operational Excellence Operations/Process Failure	10%
Safety- Dart	5%
Safety PVC	5%
Customer Experience	10%
Total	100% ³⁴⁶

Where an incentive compensation plan is reasonable, prudently incurred, not excessive, and there is a benefit to ratepayers, a Company may recover the expense of that program.³⁴⁷ In *PPL 2012* the Commission allowed incentive compensation expense because it was consistent with the Commission’s “prior decisions approving incentive compensation programs that are focused on improving operational effectiveness.”³⁴⁸ In *Aqua 2022*, the Commission found that Aqua’s stock-based compensation was linked to performance objectives that benefit consumers, as they were linked to providing quality service at a reduced cost.³⁴⁹ Similarly, the Commission has approved incentive compensation plans where employees eligible for the compensation “have direct responsibilities for customer service and regulatory compliance or are otherwise responsible for ensuring safe and reliable service to customers.”³⁵⁰ Having a financial

³⁴⁶ *Id.* at 19.

³⁴⁷ *Pa. PUC v. PPL Elec. Util. Corp.*, R-2012-2290597 (Order entered Dec. 28, 2012) (*PPL 2012*).

³⁴⁸ *PPL 2012* at 26 (citing *Pa. PUC v. Aqua Pa., Inc.*, 2008 Pa. PUC LEXIS 50, *24; *Pa. PUC v. Duquesne Light Co.*, 1987 Pa. PUC LEXIS 342 at *99-100).

³⁴⁹ *Pa. PUC v Aqua Pa. Water Co.*, 2022 Pa. PUC LEXIS 161 (Order entered May 16, 2022) (*Aqua 2022*) at **60-61.

³⁵⁰ *Pa. PUC v. Pa.-American Water Co.*, 2021 PA. PUC LEXIS 55 at *59 (Feb. 25, 2021).

metric component to the incentive compensation plan does not disqualify it from inclusion in the utility's revenue requirement, if the incentive plan establishes that eligibility for the incentive "is based on performance duties and metrics directly related to the provision of service."³⁵¹

The financial metrics related to Columbia's incentive compensation are predominantly geared towards achieving Columbia's net operating earnings per share with a 70% weighting, with the remaining 30% geared towards Occupational Health and Safety, Customer Care, Customer Satisfaction and Customer Safety.³⁵² OCA witness Mugrace testified as follows:

I am recommending that the Incentive Compensation that was paid out for achieving an Earnings Per Share ("EPS") metric be disallowed from the Company's revenue requirement increase (70%). My recommendation is based upon the fact that the majority of the Company's Incentive Compensation payments are aligned with the Company's financial goals and earnings per share growth with minimal being attributable to the benefit of customers. I do not believe that ratepayers should pay for incentive compensation, which promotes shareholders' interest and the alignment of shareholder growth. I do not see a nexus between shareholder interest and the alignment of shareholder growth and customer-oriented benefits in the area of safe and reliable utility service. The shareholder should be required to fund these costs if they believe it benefits ratepayers.³⁵³

As such, OCA witness Mugrace recommended that only the 30% of the incentive compensation costs that are geared toward customer-oriented benefits be allowed for recovery in rates.³⁵⁴ While the Company claims that the entire incentive compensation plan

(Order Feb. 25, 2021) (*PAWC 2021*).

³⁵¹ *Id.* at *60.

³⁵² OCA St. 2 at 20.

³⁵³ OCA St. 2 at 21.

³⁵⁴ OCA St. 2 at 20.

is required to retain and attract employees, Company witness Hunter provides no explanation as to why the 70% of the incentive compensation expense OCA witness Mugrace recommends disallowing is necessary to provide adequate service to ratepayers.³⁵⁵ Rather, as identified by Mr. Mugrace, the Company's position "appears to be an all or nothing approach to compensation in that without appropriate incentive compensation, employees would not be to perform their duties" or be appropriately incentivized to do so.³⁵⁶

If the Commission were to adopt the Company's view, the Company may be incentivized to reduce the portion of incentive compensation awarded based on providing ratepayers with benefits associated with operational excellence and safety improvements. Associating 30% of the Company's incentive compensation with indirect and direct ratepayer benefits does not necessitate the award of 100% of the claimed expense when, as stated by OCA witness Mugrace, "it is clearly the responsibility of the Company to share in the burden of absorbing these costs."³⁵⁷ Based on Mr. Mugrace's testimony, the OCA recommends an adjustment of \$(1,798,165) to the Company's claimed incentive compensation expense of \$2,568,807 for an allowance of \$770,642.³⁵⁸

D. Restricted Stock and Long Term Incentive (LTI)

Columbia included \$754,446 in Long-Term Incentive stock awards in its labor costs for the FPFTY period, including performance share unit and restricted stock unit

³⁵⁵ OCA St. 2SR at 11.

³⁵⁶ *Id.* at 13.

³⁵⁷ *Id.*

³⁵⁸ *Id.*

components.³⁵⁹ However, Columbia did not provide any reason as to why the 70% of these stock awards dedicated to meeting net operating earnings per share targets to its employees benefit ratepayers or provide customer-oriented service.³⁶⁰ OCA witness Mugrace recommended disallowing these costs for the FPFTY period as ratepayers should not be charged costs related to stock awards and testified as follows:

These payments are paid to directors and above (OCA Set 9-9), and vest over three years. I do not see any benefits incurred to ratepayers that are customer-oriented or customer satisfaction in the payments of restricted stock and long-term incentive (“LTI”). Rather these types of costs are typically aligned with the Company’s financial goals, and earnings per share growth with minimal benefits attributable to customers with respect to customer performance, measures, safety and environmental issues. These types of payments promote shareholders’ interest and align with shareholder growth. The Company’s shareholders should be responsible for these payments.³⁶¹

OCA witness Mugrace’s recommendation is similar to that described *supra* regarding the Company’s proposed incentive compensation generally.³⁶² While the Company claimed that if it would be at risk of losing certain employees if it did not offer LTI compensation, the Company provided no further explanation as to how the 70% of the LTI component Mr. Mugrace recommends disallowing provides direct or indirect benefits to ratepayers.³⁶³ Rather, as stated by OCA witness Mugrace, “[i]t is not the responsibility of ratepayers to be required to recover costs related to financial performance (shareholder benefit) or to reward employees with stock awards.”³⁶⁴ Columbia presented no evidence that the totality

³⁵⁹ OCA St. 2 at 21.

³⁶⁰ OCA St. 2 at 21.

³⁶¹ OCA St. 2 at 21.

³⁶² *Id.*; see also OCA St. 2 at 20.

³⁶³ OCA St. 2SR at 12-13.

³⁶⁴ *Id.*

of its LTI compensation plan is reasonable when only 30% of the plan is related to safety, customer care, customer satisfaction, or other benefits to ratepayers.³⁶⁵ As a result, the OCA recommends that only 30% of the Company's claimed LTI expense of \$754,446 be allowed for ratemaking purposes, or an adjustment of \$(528,112) for a total allowance of \$226,334.

E. Other Employee Benefits

Columbia proposes to recover \$8,915,459 in other employee benefits in the FPFTY period.³⁶⁶ As OCA witness Mugrace incorporated a vacancy rate ratio of 4.3812% for Columbia's labor expense, a corollary adjustment to Columbia's Other Employee Benefits is necessary for the FPFTY period.³⁶⁷ This adjustment reduces Columbia's revenue requirement by approximately \$543,000.³⁶⁸ While the Company disagreed with the basis of OCA witness Mugrace's recommended adjustment, the Company did not present evidence that the adjustment was incorrectly calculated and should, therefore, be accepted as reasonable.³⁶⁹ The OCA recommends that, if the Commission adopts the OCA's proposed vacancy rate ratio adjustment, that this same adjustment be flowed through the employee benefits expense claim as well.

³⁶⁵ OCA St. 2 at 20-21.

³⁶⁶ *Id.* at 23; Columbia Exh. 104 Sch. 1.

³⁶⁷ OCA St. 2 at 23.

³⁶⁸ *Id.* at 15.

³⁶⁹ OCA St. 2SR at 14.

F. Outside Services

Columbia requests \$19,014,191 in outside services for the FTY and \$18,013,909 for the FPFTY.³⁷⁰ However, Columbia included an inflation adjustment of 2.93% for the FTY and 3.05% for the FPFTY related to non-recoverable consulting costs (lobbying) and advertising.³⁷¹ As noted above, including inflation factors to adjust costs are not reasonable because these types of increase adjustments are not known and measurable and they do not reflect the true costs of providing service.³⁷²

Columbia's Outside Services costs have increased/decreased as follows:

2021-2022	4.52% decrease or \$1,100,482
2022-2023	10.16% increase or \$2,363,643
2023-2024	31.36% decrease or \$8,127,134
2025 FTY	12.83% increase or \$2,161,674
2026 FPFTY	5.26% decrease or \$1,000,282

Three-year average 2022-2024 = (8.57%)- reduction³⁷³

As shown above, Outside Services costs historically varied from a low of 4.52% to a high of 31.36%.³⁷⁴ OCA witness Mugrace testified that “[t]hese variances existed for a reason as the Company has changed its scope and scale of work activity, which is a part of the cost of doing business.”³⁷⁵ OCA witness Mugrace further testified that “Outside

³⁷⁰ OCA St. 2 at 24.

³⁷¹ *Id.* at 24.

³⁷² *Id.* at 25.

³⁷³ *Id.* at 25.

³⁷⁴ OCA St. 2SR at 15.

³⁷⁵ *Id.*

Services can fluctuate widely depending on the pool of contractors, materials and costs needed, and resources allocated. Not all the work may be performed as planned and within the time frame stated by the Company.”³⁷⁶ Though Columbia opposes the basis of Mr. Mugrace’s adjustment, the Company did not challenge the calculation of the adjustment.³⁷⁷

As such, OCA witness Mugrace recommended using the 8.57% three-year average to normalize this expense based upon the historical costs, or a reduction of \$(1,444,261) to the Company’s claimed allowance.³⁷⁸ This adjustment results in an approximately \$2 million decrease to revenue requirement.³⁷⁹

G. Corporate Insurance

Columbia proposed \$4,452,228 for Corporate Insurance in the FPFTY.³⁸⁰ Similar to other Columbia proposals, Columbia included a 3.05% inflation factor for the FPFTY when calculating its requested Corporate Insurance expense.³⁸¹ As inflation related adjustments are not known and measurable, and do not reflect the true costs of expenses, OCA witness Mugrace recommended disallowing the inflation factor, which results in an adjusted balance of \$4,320,454, which is a \$131,774 revenue requirement reduction compared to Columbia’s proposal.³⁸² While the Company disagreed with the basis of Mr. Mugrace’s adjustment, Columbia did not present evidence that the adjustment was

³⁷⁶ OCA St. 2 at 26.

³⁷⁷ OCA St. 2SR at 15.

³⁷⁸ OCA St. 2 at 26.

³⁷⁹ OCA St. 2SR at 15; OCA Exh. DM-SR-14.

³⁸⁰ OCA St. 2 at 26.

³⁸¹ OCA St. 2 at 26.

³⁸² OCA St. 2 at 27; OCA Exh. DM-SR-17.

incorrectly calculated and, therefore, OCA witness Mugrace's calculation should be accepted as reasonable.³⁸³

H. Injury and Damages

Columbia proposed \$405,057 for Injury and Damage (I&D) expense.³⁸⁴ However, Columbia included inflation factors when calculating its proposal.³⁸⁵ As such, for the same reasons as discussed above, OCA witness Mugrace removed the inflation-related adjustments to the Company's claimed I&D expense.³⁸⁶ The Company did not challenge the reasonableness of Mr. Mugrace's calculation for the adjustment, though it disagreed with the basis of the adjustment.³⁸⁷ The OCA recommends that the Commission adopt Mr. Mugrace's proposed adjustment of \$(51,257) to the Company's claimed balance of \$405,057 for a total allowance of \$353,800.³⁸⁸

I. Employee Expenses

Regarding Columbia's Employee Expenses of \$554,925 in the HTY and \$637,383 in the FPFTY, Columbia stated that these costs include employee recognition gifts, event tickets used for employee morale or team building purposes, and other entertainment expenses that support employee engagement.³⁸⁹ OCA witness Mugrace's recommended an

³⁸³ See Columbia St. 4-R at 2, 11 (identifying the corporate insurance adjustment but not commenting on the reasonableness of Mr. Mugrace's calculation).

³⁸⁴ OCA St. 2 at 27.

³⁸⁵ OCA St. 2 at 27-28.

³⁸⁶ OCA St. 2 at 27-28; OCA Exh. DM-SR-18.

³⁸⁷ See Columbia St. 4-R at 2, 11 (identifying the injuries and damages adjustment but not commenting on the reasonableness of Mr. Mugrace's calculation).

³⁸⁸ OCA St. 2 at 27.

³⁸⁹ *Id.* at 28-29.

adjusted disallowance balance is \$45,607 \$(24,083 related to 50% allowed Meals/Entertainment and \$21,524 related to Employee Expenses).³⁹⁰ This adjustment reduces Columbia's revenue requirement by approximately \$47,500.³⁹¹

Columbia's Meals/Entertainment expense in relation to its net employee expenses are as follows:

<u>Description</u>	<u>FTY Amount</u>	<u>FPFTY Amount</u>	<u>OCA</u>
Meals / Entertainment	\$84,567	\$48,166	\$24,083
Employee Expenses (net)	\$362,248	\$438,829	\$0 ³⁹²

The OCA recommends that 50% of the Company's Meals and Entertainment, or \$24,083, be allowed in rates.³⁹³ OCA witness Mugrace testified:

The Company has not broken-down these costs related to either and it is difficult to segregate out which expenses are meal-related, and which are entertainment-related. Also, I do not believe ratepayers should be paying for entertainment-related costs, company sponsored events for the benefit of the employees which may include entertainment related expenses, or other sports related entertainment. Therefore, I believe that allowing 50% of the Company's Meal and Entertainment is reasonable.³⁹⁴

Columbia's ratepayers draw no benefit from Columbia's employee entertainment events. Columbia has not broken-down these costs and OCA witness Mugrace testified that "it is difficult to segregate out which expenses are meal-related, and which are entertainment related."³⁹⁵ Ratepayers should not be paying for entertainment-related costs,

³⁹⁰ OCA St. 2SR at 16; OCA Exh. DM-SR-19.

³⁹¹ OCA St. 2SR at 16.

³⁹² OCA St. 2 at 29.

³⁹³ OCA St. 2 at 29.

³⁹⁴ *Id.*

³⁹⁵ *Id.*

company sponsored events for the benefit of the employees which may include entertainment related expenses, or other sports related entertainment.³⁹⁶ Columbia has not demonstrated that such entertainment/meal expenses are connected to incentivizing superior utility service.

In response to Mr. Mugrace's recommendation to disallow these expenses, Columbia witness Leal corrected the Company's employee expense claim, identifying that \$417,305 of the claimed expense balance related to clothing allowance and not to gifts and entertainment expenses.³⁹⁷ Mr. Mugrace accepted the clothing allowance as reasonable, but found that the difference between the total employee expenses claim and the clothing allowance, or \$21,524 were not adequately explained by the Company.³⁹⁸ Based on the Company's correction, Mr. Mugrace recommended that the \$21,524 difference be disallowed as "non-customer oriented costs" in addition to the 50% of meals and entertainment costs he recommended be disallowed in his direct testimony, or \$24,083.³⁹⁹ In total, Mr. Mugrace's updated recommendation is an adjustment of \$(45,607).⁴⁰⁰

Absent adequate justification for how Columbia's claimed entertainment/meals expenses are connected to providing safe and adequate utility service, Mr. Mugrace's recommendation to disallow the portion of the Company's claimed employee expenses substantially outweighs the evidence presented by Columbia, and should be accepted.

³⁹⁶ *Id.*

³⁹⁷ OCA St. 2SR at 16.

³⁹⁸ *Id.*

³⁹⁹ *Id.*

⁴⁰⁰ *Id.*

Therefore, the OCA recommends that the Commission adopt its proposed disallowance of \$45,607.⁴⁰¹ This adjustment has a revenue requirement impact of \$(45,607).⁴⁰²

J. Company Memberships

The OCA recommends a \$258,217 reduction to Columbia's proposed claimed membership expense balance of \$682,796.⁴⁰³ First, OCA witness Mugrace removed the Company's 2.93% and 3.05% inflation adjustment from the claimed expense as discussed *supra* in Section VII.A.⁴⁰⁴ The Company challenged the basis of Mr. Mugrace's adjustment but did not submit evidence on the reasonableness of his calculations.⁴⁰⁵

Second, Mr. Mugrace recommends removal of membership dues and other organization fees from the Company's claimed expenses with respect to Chamber of Commerce membership fees.⁴⁰⁶ Under the Public Utility Code, utilities are not permitted to recover the costs of "membership fees, dues or charges to fraternal, social or sports clubs or organizations."⁴⁰⁷ Columbia's customers see no benefit from the Company's participation in these organizations, as they are related to civic causes or lobbying; as a result, the Company should not be able to recover the costs of memberships which reflect its corporate citizenship and should be incurred below-the-line.⁴⁰⁸

⁴⁰¹ *Id.*

⁴⁰² *Id.*

⁴⁰³ OCA St. 2 at 31; OCA Exh. DM-SR-20.

⁴⁰⁴ OCA St. 2 at 31.

⁴⁰⁵ *See* Columbia St. 4-R at 2, 11 (identifying the company memberships adjustment but not commenting on the reasonableness of Mr. Mugrace's calculation).

⁴⁰⁶ OCA St. 2 at 30-31.

⁴⁰⁷ 66 Pa. C.S. § 1316.1.

⁴⁰⁸ *Cf. Pa. PUC v. Columbia Gas of Pa.*, Docket No. R-2022-3032167, 2023 PA. PUC LEXIS 173 at *27 (Order entered June 15, 2023) (tariff charge determined by the

While Columbia contends that chamber of commerce dues do not fall within the type of expenses identified under Section 1316.1 of the Public Utility Code, Columbia provided no evidence that the Company's membership in state and local chambers of commerce provide ratepayer benefits.⁴⁰⁹ Further, the averments made by Columbia regarding its participation in state and local chambers of commerce demonstrate that these are primarily social and lobbying organizations, and Columbia provides no explanation as to why it could not develop partnerships with local businesses or be attuned to local issues if it does not record these dues above the line.⁴¹⁰

Absent evidence that there is any direct benefit to ratepayers, Columbia's claim is substantially outweighed by the arguments presented by OCA witness Mr. Mugrace. Therefore, the OCA requests that Columbia not be permitted the costs of Chamber of Commerce membership, and that the Commission adjust the Company's membership expenses by \$(258,217).⁴¹¹ This adjustment reduces Columbia's revenue requirement by approximately \$353,000.⁴¹²

Commission to not be necessary for the provision of service should have been included "below the line," despite providing service which is desirable for some consumers, and could not be included in rates); *cf. Pa. PUC v. Pa.-American Water Co.*, Docket No. R-00038304, 2003 Pa. PUC LEXIS 498 (Order entered Nov. 26, 2003) at *145 (charitable contributions which the Commission lacks authority to order a public utility to make are properly considered "below the line" for ratemaking purposes, even if such contributions may provide benefits to some ratepayers).

⁴⁰⁹ OCA St. 2SR at 16-17.

⁴¹⁰ *See* Columbia St. 4-R at 20-21.

⁴¹¹ OCA St. 2 at 31; OCA Exh. DM-SR-20.

⁴¹² OCA St. 2SR at 17; OCA Exh. DM-SR-20.

K. Utilities – Fuel Used in Company Operations

Columbia proposed a \$2,075,819 balance related to its Utilities and Fuel used in Company Operations for the FPFTY.⁴¹³ As discussed in Section VII.A, OCA witness Mugrace recommends disallowing the deflation factors of 2.93% (FTY) and 3.05% (FPFTY) to arrive at an adjustment of \$28,758, an increase over the Company's HTY balance.⁴¹⁴ As such, OCA witness Mugrace also recommends adjustments related to deflation or increases in the Company's adjustments.⁴¹⁵ This adjustment increases Columbia's costs related to Utilities – Fuel Used in Company Operations by \$28,758, or \$2,104,577.⁴¹⁶ While the Company disagrees with the basis of Mr. Mugrace's adjustment, the Company provided no further evidence regarding this expense or the reasonableness of Mr. Mugrace's calculation.⁴¹⁷

L. Advertising

Columbia proposed \$391,359 in advertising expense for the FPFTY.⁴¹⁸ As discussed in Section VII.A, OCA witness Mugrace recommends disallowance of Columbia's deflation factors for the FTY and the FPFTY periods of 2.93% and 3.05%, respectively.⁴¹⁹ These adjustments increases Columbia's advertising expense by

⁴¹³ OCA St. 2 at 31; Columbia Exh. 104, Sch. 1 at 2.

⁴¹⁴ OCA St. 2 at 32.

⁴¹⁵ OCA St. 2 at 32.

⁴¹⁶ OCA St. 2 at 32; OCA Exh. DM-21.

⁴¹⁷ See Columbia St. 4-R at 2, 11 (identifying the utilities and fuel adjustment but not commenting on the reasonableness of Mr. Mugrace's calculation).

⁴¹⁸ OCA St. 2 at 32; Columbia Exh. 104, Sch. 1 at 2.

⁴¹⁹ OCA St. 2 at 32.

\$11,366.⁴²⁰ Therefore, the OCA requests that the Commission disallow \$11,366 of the Company's proposed advertising expense of \$402,724 for a total allowance of \$391,358.⁴²¹ Though the Company disagrees with the basis of Mr. Mugrace's adjustment, Columbia did not present other evidence regarding Mr. Mugrace's calculation of this adjustment.⁴²²

M. Materials and Supplies

The OCA recommends that a three-year normalization adjustment be used for one account within Columbia's claimed materials and supplies expenses for an allowance of \$558,615.⁴²³ This adjustment reduces Columbia's revenue requirement by approximately \$776,000.⁴²⁴

OCA witness Mugrace noticed that the Company's account "2020 Facilities Maintenance and Repairs Materials" increased from "\$42,478 in 2022, \$174,598 in 2023 and \$946,461 in 2024."⁴²⁵ Due to the significant increases in year-over-year trends, OCA witness Mugrace found that the cost trend is not representative of likely anticipated costs for the Company in the FPFTY and, as a result, proposed a three-year normalization to control for the high variance in the cost account.⁴²⁶ OCA witness Mugrace noted that a three-year normalization was reasonable and testified as follows:

A three-year normalization provides for a smoothing of expenses based upon prior actual costs. Operating costs incurred from prior years typically show

⁴²⁰ OCA St. 2 at 32; OCA Exh. DM-22.

⁴²¹ OCA St. 2 at 32.

⁴²² See Columbia St. 4-R at 2, 11 (identifying the advertising expense adjustment but not commenting on the reasonableness of Mr. Mugrace's calculation).

⁴²³ OCA Exh. DM-SR-24.

⁴²⁴ OCA St. 2SR at 18.

⁴²⁵ OCA St. 2 at 33.

⁴²⁶ *Id.*

a trend that can be utilized to set costs in the future. In response to OCA Set-14-5 the Company has not provided a reason for these increased costs over the years.⁴²⁷

In *PGW 2023*, the Commission made similar adjustments as a result of the OCA's recommendation, providing that:

Normalization adjustments are made to eliminate any unusual activity or event, or to stabilize fluctuations in expenses which would not reasonably be expected to recur in the future. In other words, normalization is a ratemaking technique used to smooth out the effects of an expense item that occurs at regular intervals in irregular amounts.⁴²⁸

Due to the levels of fluctuation in Columbia's materials and supplies expense, the three-year normalization adjustment proposed by OCA witness Mugrace is appropriate and should be adopted.⁴²⁹

The Company identified that account 2020 for which OCA witness Mugrace recommended a three-year normalization adjustment was inflated due to a vendor error which inadvertently assigned outside services expense to this cost account.⁴³⁰ Though the Company claims that this accounting error had no impact on its FPFTY revenue requirement, according to Mr. Mugrace:

[T]he Company has not provided any further information. As indicated by Mr. Vassalotti, the Company is currently researching the best method to correct the inadvertent O&M Expense change related to a vendor adjustment. Until such time as the Company's alters or changes its method, I am

⁴²⁷ *Id.*

⁴²⁸ *Pa. PUC v. Phila. Gas Works*, Docket No. R-2023-3037933, Order at 82-83 (Nov. 9, 2023) (*PGW 2023*) (citing *Pa. PUC v. Total Environmental Solutions, Inc.*, Docket Nos. R-00072493 (Order July 30, 2008) (*TESI*) at 72).

⁴²⁹ OCA St. 2 at 33.

⁴³⁰ OCA St. 2SR at 17.

continuing to recommend the three-year normalization adjustment of \$558,615.⁴³¹

Because Columbia has failed to provide sufficient evidence regarding how the accounting error identified by its witness was corrected in the Company's rate filing, it is appropriate to disallow any aberrant costs included in account 2020 Facilities Maintenance and Repairs Materials. Therefore, the OCA recommends that the Commission adopt Mr. Mugrace's proposed three-year normalization for this account to ensure that ratepayers are only paying for costs justified by sufficient evidence and adjust the claimed materials and supply expense of \$6,080,827 by \$(558,615) for a total allowance of \$5,522,212.⁴³²

M. NiSource Corporate Services Company (NCSC) Shared Services

The Company claimed an allowance of allocated affiliate service company charges of \$79,191,884 from the NiSource Corporate Services Company (NCSC), a sister company owned by Columbia's parent company, NiSource Inc.⁴³³ Columbia's allocated share of the costs of the services provided by NCSC are explained by OCA witness Mugrace:

In accordance with FERC Order 684, centralized service companies like NCSC must use a cost accumulation system provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. NCSC uses a billing pool system to collect costs that are applicable and billable to affiliates, including Columbia. NCSC directs all personnel to charge an affiliate directly whenever possible so that costs associated with services rendered to affiliates can be directly billed, allowing a user to directly bill a single company for costs incurred. NCSC's charges for services are billed at cost. System controls are in place that restrict certain departments or groups to

⁴³¹ *Id.* at 18.

⁴³² OCA Exh. DM-SR-24.

⁴³³ OCA St. 2 at 34.

only use billing pools that allocate to companies benefitting from the services those departments provide.⁴³⁴

However, based on the components of the cost allocated by NCSC to Columbia for which Columbia is requesting recovery from ratepayers, OCA witness Mugrace identified several necessary adjustments, including long-term incentive compensation and stock awards, Supplemental Executive Retirement Plan (SERP) costs, discretionary bonuses, and capital incentive costs.⁴³⁵ Based on these adjustments, OCA witness Mugrace recommends that \$7,669,077 of the Company's claim be disallowed, for a final allowance of \$71,522,807.⁴³⁶ The totality of Mr. Mugrace's recommended adjustments to the Company's allocated portion of NCSC expenses results in a revenue requirement impact of approximately \$10.651 million.⁴³⁷

1. Long-Term Incentive (LTI) Compensation

Columbia proposes to collect from ratepayers Long-Term Incentive (LTI) compensation and stock awards in the form of Performance Share Units (PSU) and Restricted Stock Units (RSU) to employees at the level of Director and above.⁴³⁸ For the FPFTY, the balance of these awards totals \$4,012,229.⁴³⁹ OCA witness Mugrace testified:

I believe that PSU and RSU costs appear to be predominately geared towards executive pay with no value accruing to the ratepayers of Columbia. These types of incentive costs are typically geared toward the achievement of financial performance, earnings growth and aligning with the goals of the Company's shareholders. I do not see any benefit accruing to the ratepayer

⁴³⁴ *Id.* at 35-36 (citations omitted).

⁴³⁵ *Id.* at 34-38.

⁴³⁶ OCA Exh. DM-SR-27.

⁴³⁷ OCA St. 2SR at 23.

⁴³⁸ OCA St. 2 at 36.

⁴³⁹ *Id.* at 36.

in the area of customer-oriented goals related to safety, environmental, or satisfaction.⁴⁴⁰

As such, the OCA recommends disallowing the \$4,012,229 for PSU and RSU for ratemaking purposes.⁴⁴¹ Ratepayers should not be required to pay for compensation which promotes NCSC's shareholder interests and growth.⁴⁴² As the performance metrics are the same for direct allocation to Columbia, these types of NCSC shared services costs should not be included as they provide no benefit to ratepayers, but instead benefit shareholders.⁴⁴³

While Columbia argued that LTI awards help the Company retain employees, Mr. Mugrace replied that "[t]he Company has not shown that without these stock awards it would deteriorate the Company's ability to provide safe and reliable service to its customers."⁴⁴⁴ Unlike the LTI compensation expense the Company claimed for its own activities, the allocated LTI compensation expense from NCSC is not broken down by category.⁴⁴⁵ Without detailing the basis for the award of PSUs and RSUs, OCA witness Mugrace concluded that "there is no way to discern whether the Restricted Stock / LTI compensation costs actually benefit ratepayers."⁴⁴⁶ For the reasons set forth by Mr. Mugrace, the OCA recommends that the Commission disallow \$4,012,229 from the claimed allocation of NCSC expense, or the portion related to LTI which is not demonstrated to benefit ratepayers.

⁴⁴⁰ *Id.*

⁴⁴¹ *Id.*

⁴⁴² *Id.*

⁴⁴³ *Id.*

⁴⁴⁴ OCA St. 2SR at 20-21.

⁴⁴⁵ *Id.* at 21.

⁴⁴⁶ *Id.*

2. Supplemental Executive Retirement Plan

Columbia proposes to include Supplemental Executive Retirement Plan (SERP) expense in rates.⁴⁴⁷ Specifically, Columbia included SERP costs totaling \$133,954 in the HTY, \$145,608 in the FTY and \$136,102 in the FPFTY.⁴⁴⁸ SERP costs should be disallowed for ratemaking purposes as there are no discernable benefits accruing to ratepayers from SERP.⁴⁴⁹ OCA witness Mugrace testified as follows:

These types of costs benefit and accrue to the Company by retaining key employees and are used as rewards for the benefit of key employees. Under a SERP, the Company retains the benefits in the event an employee dies, leaves or quits the Company. The Company has access to the dollars in the SERP and gets the cash value of the plan. Ratepayers should not be burdened with costs that eventually inure to the shareholders of the Company.⁴⁵⁰

There is simply no nexus between the recovery of SERP expenses from ratepayers and ratepayer benefits.⁴⁵¹ While Columbia claims that SERP costs assist the Company retain employees, there is no component of SERP costs which is shown to be tied to providing adequate, safe, or reliable service, especially considering there is no guarantee that employees will benefit from the full value of the allocated SERP expense.⁴⁵² As SERP costs do not directly benefit ratepayers, the OCA recommends disallowing Columbia's the proposed recovery of \$136,102 for the SERP cost component of the allocated NCSC expense.⁴⁵³

⁴⁴⁷ OCA St. 2 at 37.

⁴⁴⁸ *Id.*

⁴⁴⁹ *Id.*

⁴⁵⁰ *Id.*

⁴⁵¹ OCA St. 2SR at 19.

⁴⁵² *Id.* at 18-19.

⁴⁵³ *Id.* at 18.

3. Short-Term Incentive (STI) Compensation

Columbia's allocated share of NSCS expenses included a requested allowance of \$5,029,637 for short-term incentive compensation.⁴⁵⁴ Based on Mr. Mugrace's review of the STI compensation plan, and to be consistent with the portion of STI compensation directly incurred by Columbia, OCA witness Mugrace recommended that 70% of the allocated portion of NCSC STI expense be disallowed.⁴⁵⁵ Mr. Mugrace's recommended adjustment is \$(3,520,746) for a recommended allowance of \$1,508,891.⁴⁵⁶ For the reasons described *supra*, only the 30% of the Company's STI expenses which pertain directly to providing safe, adequate, and reliable services should be permitted.⁴⁵⁷

N. Diversity, Equity, and Inclusion (DEI) Expense

Columbia included a \$130,450 net balance for DEI costs.⁴⁵⁸ However, there is no evidence supporting a nexus between ratepayer benefits and Columbia's DEI incentives.⁴⁵⁹

OCA witness Mugrace testified:

I am recommending disallowance of DEI costs for ratemaking purposes. I believe these types of costs do not benefit ratepayers in the provision of safe and reliable utility service. These types of costs reflect organizational frameworks which seek to promote the fair treatment and full participation of all people who have been subject to discrimination. I do not see a nexus between DEI costs and customer-oriented benefits. These types of costs should be recovered and borne by the Company or its shareholders if it believes they provide a benefit.⁴⁶⁰

⁴⁵⁴ *Id.* at 22-23.

⁴⁵⁵ *Id.* at 23.

⁴⁵⁶ OCA Exh. DM-SR-27.

⁴⁵⁷ *Supra*, Section VII.C.

⁴⁵⁸ OCA St. 2 at 28.

⁴⁵⁹ *Id.*

⁴⁶⁰ *Id.*

While the OCA supports DEI initiatives which promote cultural competence within utilities' points of consumer contact, as with all other expenses, the Company bears the burden of proving that its proposed expense is prudent and reasonable before it can recover the cost of that expense from ratepayers.⁴⁶¹ Columbia provided no evidence regarding whether these costs actually produce benefits or any evaluated metrics to demonstrate ratepayer value.⁴⁶² Though the Company argued that its "Workplace Connections" program assists in retaining employees, the Company did not present metrics designed or evaluated to demonstrate ratepayer value and, instead, in the opinion of OCA witness Mugrace, "these appear to be costs to benefit the Company such as corporate branding, imaging and touting Company stewardships."⁴⁶³ As such, the OCA recommends disallowance of the \$130,450 of the Company's claimed DEI expense.⁴⁶⁴

O. Rate Case Expense

Columbia claims \$1,321,000 of rate case expense normalized over 12 months.⁴⁶⁵ The OCA has not recommended any adjustment to the level of expense claimed, but does recommend that the 12-month normalization period proposed by the Company be adjusted to a 14-month normalization period to reflect Columbia's historical rate case filing

⁴⁶¹ 66 Pa. C.S. § 315.

⁴⁶² OCA St. 2SR at 20.

⁴⁶³ *Id.* at 19-20.

⁴⁶⁴ *Id.* at 20.

⁴⁶⁵ Columbia Exh. 104, Schedule 2 at 16.

frequency.⁴⁶⁶ With this adjustment, the OCA recommendation reduces Columbia's revenue requirement by \$253,000.⁴⁶⁷

The Commission has consistently held that rate case expenses are normal operating expenses, and normalization should be based on the historical frequency of the utility's rate filings.⁴⁶⁸ OCA witness Mugrace reviewed Columbia's rate case filings since 2018 and found that Columbia filed six rate cases.⁴⁶⁹ This is equivalent to filing one rate case every fourteen months or 1.16 years.⁴⁷⁰ As such, OCA witness Mugrace recommended normalizing Columbia's rate case expense over 14 months, instead of the Company's proposed normalization period of 12 months.⁴⁷¹ This reduces Columbia's rate case expense from \$1,321,000 to \$1,138,793, a reduction of \$182,207.⁴⁷²

Conversely, Columbia's position is directly at odds with Commission precedent, because it requires the Commission to accept Columbia's projection that it will file a rate case again within twelve months. While the Company claims that it "anticipates a need to file annual rate cases," the Commission has consistently rejected a utility's basis for concluding that the length of time until its next anticipated rate case is the appropriate

⁴⁶⁶ OCA St. 2SR at 23.

⁴⁶⁷ OCA St. 2SR at 24.

⁴⁶⁸ *Popowsky v. Pa. PUC*, 674 A.2d 1149, 1154 (Pa. Cmwlth. 1996); *Pa. PUC v Columbia Water Co.*, 2009 Pa. PUC LEXIS 1423 (2009); *Pa. PUC v. National Fuel Gas Distribution Corp.*, 84 Pa. PUC 134, 175 (1995); *Pa. PUC v Roaring Creek Water Co.*, 73 Pa. PUC 373, 400 (1990); *Pa. PUC v. West Penn Power Co.*, 119 PUR4th 110, 149 (Pa. PUC 1990).

⁴⁶⁹ OCA St. 2SR at 23.

⁴⁷⁰ *Id.*

⁴⁷¹ *Id.* at 23-24.

⁴⁷² *Id.*; OCA Sch. DM-SR-28.

period over which to normalize rate case expense.⁴⁷³ There is no reason to guess rate case filing frequency when the facts are readily observable and able to be reflected in rates.

By adjusting the normalization period from 12-months to 14-months, Columbia's rate case expense will be normalized based on its historic frequency of rate filings. The Commission should accept Mr. Mugrace's adjustment to the rate case expense, as it conforms with Commission precedent, and reduce the annual normalized rate case expense by \$182,207 for an allowance of \$1,138,793.⁴⁷⁴ Accepting this adjustment produces an overall revenue requirement decrease of approximately \$253,000.⁴⁷⁵

P. Uncollectible Expense

OCA witness accepted Columbia's computation of its level of uncollectible expense.⁴⁷⁶ However, as the totality of Mr. Mugrace's O&M expense adjustments are being grossed-up by a revenue conversion factor of 1.38698, OCA witness Mugrace's uncollectible expense is calculated at \$(488,873) as OCA witness Mugrace's overall revenue requirement decrease of \$36,316,933 multiplied by the uncollectible account factor of 0.01346130.⁴⁷⁷ As a result, if the Commission accepts the revenue requirement recommendation supported by OCA witness Mugrace, the OCA recommends that the

⁴⁷³ Compare OCA St. 2SR at 23 (describing the Company's response to Mr. Mugrace's proposed adjustment) with *Pa. PUC v. Columbia Water Co.*, Docket No. R-2023-3040258 (Order entered Jan. 18, 2024) at 34 ("an actual, historical filing pattern offers the best evidence for anticipating a company's future behavior, with respect to filing its next base rate case").

⁴⁷⁴ OCA Sch. DM-SR-28.

⁴⁷⁵ OCA St. 2SR at 24.

⁴⁷⁶ OCA St. 2 at 40.

⁴⁷⁷ OCA St. 2SR at 24-25; OCA Exh. DM-SR-1, DM-SR-9, DM-SR-29.

Commission apply Mr. Mugrace's methodology for the calculation of the applicable uncollectible expense adjustment.

Q. Rider Universal Service Plan (USP)

Columbia proposed recovery of \$31,862,500 in the FPFTY related to its Rider USP for its universal service program reconciling mechanism, and \$1,235,965 in the FPFTY related to its Rider EE for its energy efficiency program reconciling mechanism.⁴⁷⁸ As discussed in Section XIII.G.5, OCA witness Colton recommended that \$220,000 of administrative costs be disallowed.⁴⁷⁹ Mr. Colton identified that Columbia does not budget internal CAP administrative costs or any universal service program at the program level and does not provide the constituent categories of costs within the claim administrative costs account.⁴⁸⁰ As stated by Mr. Colton, "[t]he purpose of recovering costs through the Rider USP is to ensure that budgeted (or projected) costs can be reconciled against actual costs," which is inconsistent with the Company's stated budgeting practices.⁴⁸¹ Based on Mr. Colton's testimony, OCA witness Mugrace recommended a \$220,000 disallowance from the Rider USP balance.⁴⁸² This adjustment reduces the revenue requirement by approximately \$306,000.⁴⁸³

⁴⁷⁸ Columbia Exh. 104, Sch. 1 at 2; OCA St. 2 at 41.

⁴⁷⁹ *Infra* at Section XIII.G.5.

⁴⁸⁰ OCA St. 5 at 112-14.

⁴⁸¹ *Id.* at 113.

⁴⁸² OCA St. 2SR at 25; OCA Exh. DM-SR-31.

⁴⁸³ *Id.*

R. Depreciation and Amortization Expense

The Company proposed a depreciation and amortization expense of \$149,371,200 and a five-year net negative salvage expense of \$5,484,681.⁴⁸⁴ As described *infra*, OCA witness Garrett recommended that Columbia switch depreciation grouping procedures from the ELG to the ALG.⁴⁸⁵ OCA witness Garrett calculated that, if Columbia's depreciation expense were calculated using the ALG procedure instead of the ELG procedure, then the expense would be reduced by \$45,802,423.⁴⁸⁶ Based on OCA witness Garrett's recommendation, OCA witness Mugrace recommended a depreciation expense balance adjustment of \$(45,802,423).⁴⁸⁷ Consistent with Mr. Mugrace's recommendation to disallow inflation-related adjustments to the Company's claimed utility plant in service balance, OCA witness Mugrace further reduced the Company's depreciation expense claim by \$236,476.⁴⁸⁸ The sum of these two adjustments is a reduction of \$46,038,898 to the Company's claimed depreciation expense.⁴⁸⁹ After grossing this amount up to account for federal and state taxes and uncollectible expense, this adjustment reduces Columbia's requested revenue requirement by \$63.615 million.⁴⁹⁰

⁴⁸⁴ OCA St. 2 at 42.

⁴⁸⁵ OCA St. 3 at 61-66.

⁴⁸⁶ OCA Exh. DJG-17.

⁴⁸⁷ OCA St. 2SR at 25-26.

⁴⁸⁸ OCA St. 2 at 42.

⁴⁸⁹ *Id.*; OCA Exh. DM-SR-32.

⁴⁹⁰ OCA St. 2SR at 26.

S. Conclusion Regarding Expenses

Columbia has the burden of proving each element of its general rate increase request, which includes the operations and maintenance and administrative and general expenses the Company estimates it will incur in its future test years.⁴⁹¹ The Company's request to recover costs which are not supported by sufficient evidence because they rely on inflationary adjustments or to recover costs this provide no ratepayer benefit but directly benefit the Company's image as a corporate citizen or provide greater return to its shareholders are unsupported and should be disallowed. The OCA requests that the Commission assign significant weight to the evidence and testimony submitted by OCA witness Mugrace regarding the Company's requested expense allowances that are not shown to be known and measurable or to provide direct ratepayer benefit. The sum of the OCA's recommended operating expense adjustments is \$(17,185,516).⁴⁹²

VIII. TAXES

A. Income Taxes

Columbia claimed a total income tax expense of \$72,811,341, including federal income tax, state income tax, deferred income tax, excess deferred income tax, and amortization of investment tax credit components.⁴⁹³ OCA witness Mugrace adopted the Company's method of calculating its tax obligations.⁴⁹⁴ However, due to the recommendations made by OCA witnesses Mugrace and Garrett regarding the Company's

⁴⁹¹ 66 Pa. C.S. § 315(a)(e).

⁴⁹² OCA St. 2SR at 4.

⁴⁹³ OCA St. 2 at 44.

⁴⁹⁴ *Id.* at 45.

claimed rate base, O&M expense, depreciation expense, capital structure, and return on equity, Mr. Mugrace recommended an income tax expense allowance of \$(55,267,855), which is \$17,543,486 greater than the Company's claimed income tax expense of \$(72,811,341).⁴⁹⁵

Mr. Mugrace explained how he arrived at his recommended adjustment as follows:

Using the Company's methodology shown on the Company's Exhibit 107 Page 8, with a Federal Income Tax Rate (FIT) of 21% and a PA State Income Tax Rate (SIT) of 7.49%, I utilized the flow through of my Rate Base and Operating Income adjustments to compute my State and Federal Income Tax balance and the Deferred Tax adjustments. In response to OCA 9-42 the Company updated its excess tax depreciation over book depreciation by \$2,834,217 and a balance of \$32,331,282. With respect to the Company's Statutory Adjustments of (\$223,215,150), I made an adjustment to the Company's Interest Expense, in that I used my recommended Rate Base Balance of \$3,883,435,478 times the recommended weighted Cost of Short-Term and Long-Term Debt of 2.60%, as recommended by Mr. Garrett which equals \$100,789,131. This is \$9,422,861 greater than the Company's proposed Interest Expense balance of \$91,366,270. I have accepted the Company's balance related to its EDIT of \$2,498,191. My total recommended State Income Tax is \$16,023,187; my total recommended Federal Income Tax is \$69,205,671 and my total Deferred Income Taxes are (\$38,689,948).⁴⁹⁶

Overall, the OCA accepts the Company's methodology for calculating its income tax expense and recommends that the Commission adopt Mr. Mugrace's calculated adjustment of \$17,543,486 for an income tax allowance of \$(55,267,855) consistent with the recommendations of OCA witnesses Mugrace and Garrett's regarding the appropriate revenue requirement for the Company.

⁴⁹⁵ OCA St. 2SR at 4; OCA Exh. DM-SR-34.

⁴⁹⁶ OCA St. 2 at 45.

B. Taxes Other Than Income Tax

The Company requested a taxes other than income expense allowance of \$4,500,883, which includes payroll taxes, property taxes, license and franchise, sales and use taxes and other taxes other than income taxes.⁴⁹⁷ OCA witness Mugrace recommended adjustments to the Company's payroll tax and property tax allowances based on his recommendations regarding Columbia's claimed labor expense and utility plant in service balances, respectively.⁴⁹⁸ Mr. Mugrace described his adjustment to the Company's claimed payroll tax as follows:

Since I adjusted labor and incentive compensation, I am making the associated adjustments to reflect my recommended levels using the Company's Payroll Tax Rate of 7.2234%. My Payroll Tax balance is \$2,798,543, a reduction of \$187,573.⁴⁹⁹

Further, Mr. Mugrace stated that:

I also adjusted the Property Taxes to reflect the changes in my recommended UPIS balance. I used the Company's Property tax level of \$1,372,160 to the Company's proposed UPIS balance of \$5,219,879,723 and calculated a composite tax rate of 0.00026287%. Using my recommended UPIS balance of \$5,205,372,014 times the composite tax rate of 0.00026287%, I computed a Property Tax expense of \$1,368,336, a reduction of \$3,824.⁵⁰⁰

Based on the sum of these two adjustments, Mr. Mugrace's overall recommendation to the Company's taxes other than income tax is an adjustment of \$(191,397) for an allowable balance of \$4,309,435.⁵⁰¹ The OCA recommends that, if Mr. Mugrace's

⁴⁹⁷ OCA St. 2 at 43.

⁴⁹⁸ *Id.*

⁴⁹⁹ *Id.*

⁵⁰⁰ *Id.*

⁵⁰¹ *Id.*

adjustments to Columbia's claimed labor expense and utility plant in service balances are adopted by the Commission, then the proposed adjustment to taxes other than income tax should be adopted as well.

IX. RATE OF RETURN

A. Introduction

In this proceeding, Columbia proposed an excessive 11.35% return on equity which includes a 0.25% upward management performance adder adjustment.⁵⁰² Moreover, Columbia proposed a capital structure of 54.4% common equity and 45.6% debt for its operations.⁵⁰³ As demonstrated by OCA witness David Garrett and discussed in this brief, Columbia's proposed return on equity and capital structure should be rejected as they are not supported by substantial evidence and would result in unjust and unreasonable rates. Mr. Garrett recommends the following:

- An overall cost of capital of 7.06%
- A Return on Equity (ROE) of 8.9%
- An imputed capital structure of 50% common equity and 50% debt for ratemaking purposes
- That the management premium performance adder be denied.⁵⁰⁴

Mr. Garrett's recommendations make proper use of accepted financial theory and realistically reflect today's capital cost environment. OCA witness Garrett's proposed adjustments to the Company's ROE and capital structure result in an overall 7.06% weighted rate of return.⁵⁰⁵ Adopting OCA witness Garrett's recommended adjustments to

⁵⁰² OCA St. 3 at 12.

⁵⁰³ OCA St. 3 at 50; Columbia Exh. VVR-5.

⁵⁰⁴ OCA St. 3 at 3, 56.

⁵⁰⁵ OCA St. 3 at 3.

ROE and capital structure would result in a revenue requirement reduction of \$54.6 million.⁵⁰⁶ In recognition of the facts and analysis presented below, Columbia's requests should be rejected, and the OCA's cost of capital recommendations should be adopted.

B. Columbia's proposed capital structure strays significantly from Columbia's proposed proxy group.

Columbia's requested capital structure is inappropriate and inconsistent with Pennsylvania case law. Columbia's requested capital structure includes a high common 54.4% equity ratio, 43.28% long-term debt, and 2.32% short-term debt.⁵⁰⁷

OCA witness Garrett used the same utility proxy group as Columbia witness Rea, which contains six natural gas companies and is referred to as "Gas LDC Group."⁵⁰⁸ However, Columbia witness Rea also conducted a cost of equity analysis with a "Combination Utility Group" proxy group and a "Non-Regulated Utility Group" proxy group.⁵⁰⁹ OCA witness Garrett testified that "it is not necessary to perform cost of equity analyses on a proxy group beyond the Gas LDC Group."⁵¹⁰ OCA witness Garrett further testified:

The same types of unreasonable assumptions and inputs employed by Mr. Rea on the Gas LDC Group (as discussed later in my testimony) also apply to his non-utility group modeling. For that reason alone, the results of the non-utility modeling should be rejected. Moreover, this model adds no marginal value to the process of developing a reasonable estimate for Columbia's cost of equity. The companies included in Mr. Rea's non-utility group are undoubtedly less comparable than those included in the Gas LDC Group. For these reasons, the Commission should reject the results of the

⁵⁰⁶ OCA St. 3 at 3-4.

⁵⁰⁷ OCA St. 3SR at 9; Columbia St. 8 at 43-44.

⁵⁰⁸ OCA St. 3 at 12.

⁵⁰⁹ OCA St. 3 at 12.

⁵¹⁰ OCA St. 3 at 51.

non-utility modeling as providing a meaningful indication of Columbia's cost of equity in this case.⁵¹¹

Importantly, precedent recognizes that the capital structure for companies that are wholly-owned subsidiaries, like Columbia, is not limited to an actual capital structure, and the Commission may make adjustments where circumstances may be unfair to customers. The Pennsylvania Superior Court has held that the capital structure of utilities that are wholly-owned subsidiaries may not be one which it would maintain if it were obliged to obtain its debt and equity financing on the open market rather than from a parent company.⁵¹²

The Court further explained:

In such instances the actual capital structure may be weighted too heavily on the debt side or the equity side...The use of the actual capital structure in such peculiar circumstances might be unfair to either the utility or its customers, depending upon whether debt or equity is disproportionately high. Under such circumstances the commission must make adjustments based upon substantial evidence in order to reach a fair result.⁵¹³

Additionally, according to Value Line, the average capital structure mix for the proxy group consists of 55% debt and 45% equity.⁵¹⁴ This debt ratio is notably higher than Columbia's proposed capital structure consisting of only 46% debt.⁵¹⁵ There are nearly 2,000 firms in U.S. industries with higher debt ratios than 50% and with an average debt ratio of approximately 63%.⁵¹⁶

⁵¹¹ OCA St. 3 at 57.

⁵¹² *Riverton Consol. Water Co. v. Pa. PUC*, 140 A.2d 114 at 121 (Pa. Super. 1958).

⁵¹³ *Id.*

⁵¹⁴ OCA St. 3 at 50.

⁵¹⁵ *Id.*

⁵¹⁶ OCA St. 3 at 51.

In this case, the Commission should adopt Mr. Garrett's capital structure in the interest of fairness to ratepayers. Authorizing a regulatory capital structure for Columbia with a common equity ratio higher than other comparable utility companies without justification will result in unreasonably high rates. Simply put, Columbia failed to meet its burden of proof in establishing that a 54.4% equity ratio is supportable or reasonable for ratemaking purposes.

OCA witness Garrett's use of Columbia's Gas LDC proxy group is reasonable as it only includes natural gas utilities. As such, OCA witness Garrett's imputed 50% equity, 50% debt capital structure should be adopted.

C. Debt Cost Rate.

The OCA accepts Columbia's debt cost rate.

D. The OCA's recommended return on common equity is supported by substantial evidence and results in just and reasonable rates.

In arriving at a recommended 8.9% ROE, OCA witness Garrett used a Discounted Cash Flow (DCF) model, including an Analyst-Growth and Sustainable Growth model, and a Capital Asset Pricing Model (CAPM) at both the proxy debt ratio and at the Columbia-proposed debt ratio (also known as the Hamada CAPM) to the proxy group provided by Columbia.⁵¹⁷

The below table is OCA witness Garrett's cost of equity model results⁵¹⁸:

⁵¹⁷ OCA St. 3 at 57-58.

⁵¹⁸ OCA St. 3 at 57.

Model	Cost of Equity
CAPM (at Proxy Debt Ratio)	8.9%
Hamada CAPM (at Company-Proposed Debt Ratio)	8.7%
DCF Model (Analyst Growth)	7.5%
DCF Model (Sustainable Growth)	7.3%
Model Average	8.1%
Model Range	7.3% -- 8.9%
Recommended ROE	8.9%

As shown above, OCA witness Garrett recommended the highest cost of equity result from the range of cost of equity calculations: 8.9%.⁵¹⁹

OCA witness Garrett's rate of return recommendations are as follows⁵²⁰:

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long-Term Debt	47.68%	5.2%	2.5%
Short-Term Debt	2.32%	5.0%	0.1%
Common Equity	50.00%	8.9%	4.5%
Total	100.0%		7.06%

1. Mr. Garrett's Discounted Cash Flow model is reasonable and supported by substantial evidence.

⁵¹⁹ OCA St. 3 at 57.

⁵²⁰ OCA St. 3 at 58.

The Discounted Cash Flow (DCF) Model is commonly presented in rate proceedings and considered when assessing a utility's authorized ROE.⁵²¹ There are three primary inputs in the DCF Model: (1) stock price; (2) dividend; and (3) the long-term growth rate.⁵²² The stock prices and dividends are known inputs based on recorded data, while the growth rate must be estimated.⁵²³

OCA witness Garrett used two variants of the DCF model: one using analysts' projected growth rates published by Value Line and the other using the maximum sustainable growth rate based on the U.S. Gross Domestic Product (GDP). The results of these DCF analyses are 7.5% and 7.3%, respectively.⁵²⁴

a. OCA witness Garrett's Analyst Growth Rate DCF relies on Value Line's publication without modification.

Analyst growth rates refer to short-term projections of earnings growth published by institutional research analysts such as Value Line and Bloomberg.⁵²⁵ Mr. Garrett used Value Line's growth rate, which resulted in a 7.5% ROE when inputted into the DCF formula.⁵²⁶ As Mr. Garrett testified in response to Mr. Rea's critique, "[t]his means that Value Line analysts project annual dividend growth for the proxy companies at an annual rate not much higher than projected GDP growth, which is about 3.7% over the long-run."⁵²⁷

³⁹⁴ OCA St. 3 at 24-25.

⁵²² OCA St. 3 at 20.

⁵²³ *Id.*

⁵²⁴ OCA St. 3 at 27.

⁵²⁵ OCA St. 3 at 24.

⁵²⁶ OCA St. 3SR at 5; OCA Exh. DJG-6.

⁵²⁷ OCA St. 3SR at 5.

b. OCA witness Garrett's Sustainable Growth Rates DCF is reasonably based on the U.S. Gross Domestic Product growth.

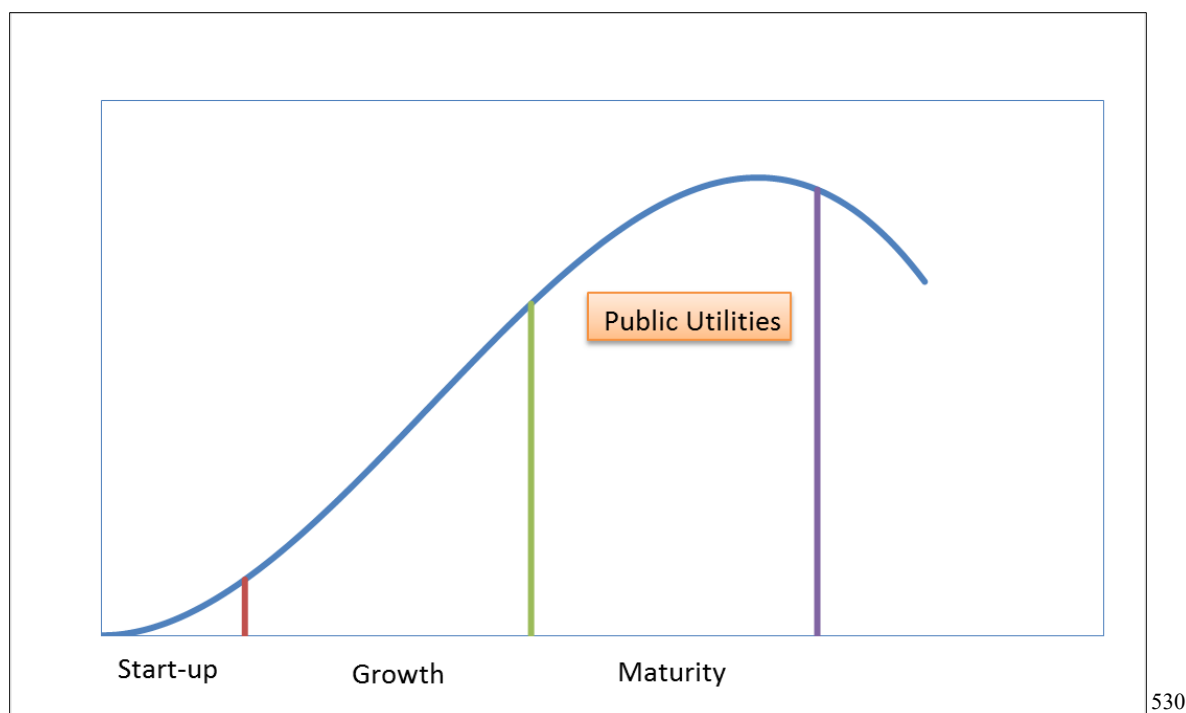
To make the DCF Model a viable and practical model, OCA witness Garrett utilized a sustainable growth rate DCF model utilizing the U.S. GDP growth rate.⁵²⁸ Mr. Garrett testified as follows regarding the need to account for a Company's growth over time:

In order to make the DCF Model a viable, practical model, an infinite stream of future cash flows must be estimated and then discounted back to the present. Otherwise, each annual cash flow would have to be estimated separately. Some analysts use "multi-stage" DCF Models to estimate the value of high-growth firms through two or more stages of growth, with the final stage of growth being sustainable. However, it is not necessary to use multi-stage DCF Models to analyze the cost of equity of regulated utility companies. This is because regulated utilities are already in their "sustainable," low growth stage. Unlike most competitive firms, the growth of regulated utilities is constrained by physical service territories and limited primarily by ratepayer and load growth within those territories.⁵²⁹

OCA witness Garrett provided the following illustration of the industry life cycle:

⁵²⁸ OCA Exh. DJG-6.

⁵²⁹ OCA St. 3 at 24-25.



In an industry's early stages, there are ample opportunities for growth and profitable investment.⁵³¹ However, in the maturity stage, growth opportunities diminish and firms choose to pay out a larger portion of their earnings in the form of dividends instead of reinvesting them in operations to pursue further growth opportunities.⁵³² As such, OCA witness Garrett testified that once a firm is at the maturity phase, the cost of equity should be determined based on a stable growth DCF Model with one sustainable growth rate.⁵³³

Importantly, the aggregate growth rate of the economy is typically a limiting factor for the growth rate in the DCF model.⁵³⁴ Mr. Garrett explained that for mature companies

⁵³⁰ OCA Exh. DJG-6.

⁵³¹ OCA St. 3 at 25.

⁵³² OCA St. 3 at 25-26.

⁵³³ OCA St. 3 at 26.

⁵³⁴ OCA St. 3 at 26.

in mature industries such as public utilities, the terminal growth rate should not exceed nominal GDP growth as follows:

A fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates. Thus, the terminal growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true when the DCF Model is conducted on public utilities because these firms have defined service territories. As stated by Dr. Damodaran: “[i]f a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value.”

In fact, it is reasonable to assume that a regulated utility would grow at a rate that is less than the U.S. economic growth rate. Unlike competitive firms, which might increase their growth by launching a new product line, franchising, or expanding into new and developing markets, utility operating companies with defined service territories cannot do any of these things to grow. Gross Domestic Product (“GDP”) is one of the most widely used measures of economic production and is used to measure aggregate economic growth.⁵³⁵

According to the Congressional Budget Office’s Budget Outlook, the long-term forecast for nominal U.S. GDP growth is 3.7%.⁵³⁶ For mature companies in mature industries, such as utility companies, the terminal growth rate should not exceed nominal GDP growth. The sustainable growth rate DCF model resulted in a 7.3% ROE, which is very similar to the analyst growth rate DCF model’s 7.5% ROE result.⁵³⁷

- c. **OCA witness Garrett’s DCF model relies on data from financial institutions without alteration while Columbia witness Rea’s DCF analysis subjectively overstates the appropriate rate of return.**

⁵³⁵ OCA St. 3 at 26.

⁵³⁶ OCA St. 3 at 27.

⁵³⁷ OCA St. 3SR at 5; OCA Exh. DJG-6.

Both the DCF Model utilizing the analyst growth rates and the DCF Model utilizing a sustainable growth rate resulted in a similar cost of equity: 7.5% (Analyst Growth) and 7.3% (Sustainable Growth).⁵³⁸ As such, the highest DCF result that OCA witness Garrett was able to obtain was 7.5%.

On the other hand, Columbia witness Rea's DCF analysis is overstated through the use of unsustainably high growth rates for some proxy companies.⁵³⁹ Mr. Rea's DCF conducted on the Gas LDC group produced a result of 10.97%, which is clearly excessive.⁵⁴⁰ In fact, Mr. Rea eliminated several results of the proxy companies from his DCF analysis because he subjectively considered them to be too low.⁵⁴¹ Specifically, Mr. Rea removed any individual DCF estimate below 7%.⁵⁴² Yet, Mr. Rea did not remove any of his higher DCF results for the proxy companies, which are as high as 13.4%.⁵⁴³ Additionally, OCA witness Garrett testified that the perpetual growth rates that Mr. Rea used for some proxy companies are unrealistically high and are unsustainable as follows:

For example, Mr. Rea assumes an annual long-term growth rate of 10% for Southwest Gas. This means Mr. Rea is suggesting the company's earnings will growth by 10% each year, every year, in perpetuity. This 10% growth estimate is from Value Line. However, Value Line is representing this to be a short-term annual growth rate over the next few years. It is Mr. Rea who is suggesting that this annual earnings growth rate can be achieved each year in perpetuity.⁵⁴⁴

⁵³⁹ OCA St. 3 at 27.

⁵⁴⁰ OCA St. 3 at 27.

⁵⁴¹ OCA St. 3 at 27-28.

⁵⁴² OCA St. 3 at 28.

⁵⁴³ OCA St. 3 at 28.

⁵⁴⁴ OCA St. 3 at 28.

As Mr. Rea is using long-term growth rates that Value Line represents as short-term growth rates over the next few years, the cost of equity results indicated by Mr. Rea's DCF model are unreasonably high and should not be adopted.⁵⁴⁵ By comparison, OCA witness Garrett uses the long-term growth rate provided by Value Line (analyst expectations model) and GDP (sustainable growth model) as provided by the U.S. Congressional Budget Office.⁵⁴⁶ As such, OCA witness Garrett's DCF results are based on a solid mathematical foundation without alternation.

2. Capital Asset Pricing Model

The Capital Asset Pricing Model (CAPM) is a market-based model founded on the principle that investors expect higher returns for incurring additional risk.⁵⁴⁷ The CAPM estimates this expected return.⁵⁴⁸

The Commission has recently held that the CAPM is properly used as a check on the reasonableness of the DCF:

We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return.⁵⁴⁹

In calculating the CAPM, OCA witness Garrett determined the appropriate values or ranges of the three model inputs: 1) risk-free rate; (2) beta, and; (3) equity risk premium.

⁵⁴⁵ OCA St. 3 at 28.

⁵⁴⁶ OCA St. 3 at 27.

⁵⁴⁷ OCA St. 3 at 28.

⁵⁴⁸ *Id.*

⁵⁴⁹ *Pa. PUC v Aqua Pennsylvania, Inc.*, Docket No. R-2021-3027385, 2022 Pa PUC LEXIS 161, *83, (Opinion and Order entered May 16, 2022) (*Aqua 2022*).

OCA St. 3 at 29. OCA witness Garrett’s CAPM resulted in an 8.9% cost of equity, but only if the proxy group average debt ratio is assumed.⁵⁵⁰ Otherwise, OCA witness Garrett calculated an 8.7% CAPM.⁵⁵¹

a. OCA witness Garrett’s Risk Free Rate is reasonably based on U.S. Treasury securities.

The risk-free rate is simply the level of return investors can achieve without assuming any risk.⁵⁵² OCA witness Garrett testified that, even though no investment is technically devoid of risk, investors often use U.S. Treasury securities to represent the risk-free rate because they accept that those securities essentially contain no default risk.⁵⁵³ The Treasury issues securities with different maturities, including short-term Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.⁵⁵⁴ OCA witness Garrett noted that “[s]hort-term rates are subject to greater volatility and thus can lead to unreliable estimates. Instead, long-term Treasury bonds are usually used to represent the risk-free rate in the CAPM.”⁵⁵⁵

OCA witness Garrett considered a 30-day average of daily U.S. Treasury yield curve rates on 30-year Treasury bonds for the risk-free rate, which result in a risk-free rate of 4.89%.⁵⁵⁶

⁵⁵⁰ OCA St. 3 at 31.

⁵⁵¹ *Id.*

⁵⁵² OCA St. 3 at 29.

⁵⁵³ OCA St. 3 at 29.

⁵⁵⁴ *Id.*

⁵⁵⁵ OCA St. 3 at 30.

⁵⁵⁶ OCA St. 3 at 30.

b. OCA witness Garrett's beta is the most recent Value Line beta.

Beta represents the sensitivity of a given security to movements in the overall market. OCA St. 3 at 30. An index such as the S&P 500 Index is used as a proxy for the market portfolio.⁵⁵⁷ A security with a beta greater than 1.0 is riskier than the market portfolio while a security with a beta less than 1.0 is less risky than the market portfolio.⁵⁵⁸

Mr. Garrett used betas recently published by Value Line Investment Survey.⁵⁵⁹ The beta for each proxy company is less than 1.0, and the average beta for the total proxy group is only 0.83. As such, OCA witness Garrett noted that there is an objective measure to prove the concept that utility stocks are less risky than average stock in the market.⁵⁶⁰ OCA witness Garrett further testified that “[w]hile there is evidence suggesting that betas published by sources such as Value Line may actually overestimate the risk of utilities (and thus overestimate the CAPM), I used the betas published by Value Line in the interest of reasonableness.”⁵⁶¹

⁵⁵⁷ *Id.*

⁵⁵⁸ OCA St. 3 at 30.

⁵⁵⁹ OCA St. 3 at 31.

⁵⁶⁰ OCA St. 3 at 31.

⁵⁶¹ *Id.*

c. OCA witness Garrett appropriately relied on expert surveys and an implied equity risk premium based on respected financial institutions and scholars.

The Equity Risk Premium (ERP) is arguably the most important factor in estimating the cost of capital through the CAPM.⁵⁶² OCA witness Garrett used two methods to estimate the ERP: (1) expert surveys and (2) calculating the implied ERP.

The expert survey approach to estimating ERP relies on surveys of professors, analysts, chief financial officers, and other executives, asking what experts think the ERP is.⁵⁶³ The IESE Business School conducts an expert survey every year and its 2025 survey reported an average ERP of 5.5%.⁵⁶⁴

OCA witness Garrett testified that the implied equity risk premium approach is arguably the best approach. OCA witness Garrett provided an extensive discussion of the implied ERP calculation.⁵⁶⁵ OCA witness Garrett testified as follows regarding the calculation of an implied ERP:

After collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, I calculated the dividend yield, buyback yield, and gross cash yield for each year. I also calculated the compound annual growth rate (g) from operating earnings. I used these inputs, along with the risk-free rate and current value of the index to calculate a current required return on the U.S. equity market of 9.9%. I subtracted the risk-free rate to arrive at the implied equity risk premium of 5.0%. Dr. Damodaran, one of the world's leading experts on the ERP, promotes the implied ERP method discussed above. He calculates monthly and annual implied ERPs with this method and publishes his results. Dr. Damodaran's average ERP estimate for June of 2025 using several implied ERP variations

⁵⁶² OCA St. 3 at 37.

⁵⁶³ OCA St. 3 at 34.

⁵⁶⁴ OCA St. 3 at 34.

⁵⁶⁵ OCA St. 3 at 34-36.

was 4.3%. Additionally, Kroll (formerly Duff & Phelps) recently published an ERP estimate of 5.5%.⁵⁶⁶

For his final ERP estimate used in the CAPM analysis, OCA witness Garrett considered the results of expert surveys, the estimated ERP reported by Kroll, the estimated ERP calculated by Dr. Damodaran, and the implied ERP based on Mr. Garrett's calculations.⁵⁶⁷ The results were as follows:

IESE Business School Survey	5.5%
Kroll (Duff & Phelps) Report	5.5%
Damodaran (average)	4.3%
Garrett	5.0%
Average	5.1%

568

OCA witness Garrett used the average from these sources to arrive at the 5.1% ERP for his CAPM.⁵⁶⁹

d. Conclusion as to the OCA's CAPM recommendation.

Using inputs for the risk-free rate, beta, and ERP discussed above, OCA witness Garrett estimated that Columbia's CAPM cost of equity is 8.9%, but only if the proxy group average debt ratio is assumed.⁵⁷⁰ As 8.9% is the highest cost of equity OCA witness

⁵⁶⁶ OCA St. 3 at 36.

⁵⁶⁷ OCA St. 3 at 37.

⁵⁶⁸ OCA St. 3 at 37.

⁵⁶⁹ *Id.*

⁵⁷⁰ OCA St. 4 at 39.

Garrett was able to reasonably obtain, Mr. Garrett recommended an 8.9% return on equity for Columbia.⁵⁷¹

e. Response to Mr. Rea's CAPM analysis and other issues.

Columbia witness Rea's traditional CAPM analysis produced an 11.05% cost of equity for the Gas LDC Group.⁵⁷² Mr. Rea also conducted another variation of the CAPM called the "empirical CAPM" (ECAPM), which resulted in a 11.21% cost of equity for the Gas LDC Group.⁵⁷³ Columbia witness Rea also conducted another type of risk premium analysis, which resulted in an 11.25% cost of equity for the Gas LDC Group.⁵⁷⁴ Moreover, Mr. Rea also applied a size premium to his final results, which caused his CAPM results to be as high as 11.66%.⁵⁷⁵

i. Mr. Rea's CAPM Beta is Outdated.

While OCA witness Garrett and Columbia witness Rea both relied on betas published by Value Line, since the time Mr. Rea conducted his analysis, Value Lines' betas have been notably reduced.⁵⁷⁶ OCA witness Garrett testified that "[t]his indicates the relative stability of utility stock prices during times of market volatility, and is not surprising."⁵⁷⁷ Mr. Rea used an average beta of 0.91 for the Gas LDC Group.⁵⁷⁸

⁵⁷¹ OCA St. 3 at 38.

⁵⁷² OCA St. 3 at 38.

⁵⁷³ OCA St. 3 at 38.

⁵⁷⁴ OCA St. 3 at 38-39.

⁵⁷⁵ OCA St. 3 at 39.

⁵⁷⁶ OCA St. 3 at 39.

⁵⁷⁷ OCA St. 3 at 39.

⁵⁷⁸ OCA St. 4 at 39.

Using the same proxy group with more recent market data from Value Line, OCA witness Garret used an average beta of 0.80 for the Gas LDC Group.⁵⁷⁹ While OCA witness Garrett agrees that Value Line can be a reliable source for beta estimates, the more recent betas published by Value Line are considerably lower than those used by Mr. Rea in his CAPM analysis and should be utilized as they are more up-to-date.⁵⁸⁰

ii. Mr. Rea's Equity Risk Premiums are excessive.

Columbia witness Rea considered ERPs in his CAPM analysis ranging from 6.83% to 7.17%.⁵⁸¹ By comparison, the ERPs OCA witness Garrett considered were from objective and reliable sources, which resulted in an average ERP of 5.1%.⁵⁸²

MR. Rea's ERP is significantly higher than other estimates for ERP. For example, the 2025 IESE Business School expert survey reports an average ERP of 5.5%.⁵⁸³ Similarly, Kroll (formerly Duff & Phelps) recently estimated an ERP of 5.5%.⁵⁸⁴ Dr. Damodaran, one of the leading experts on the ERP, recently estimated an ERP of only 4.3%.⁵⁸⁵ The following chart shows that Mr. Rea's ERP estimate is higher than other reasonable estimates for the ERP:

⁵⁷⁹ OCA St. 3 at 39.

⁵⁸⁰ OCA St. 3 at 39-40.

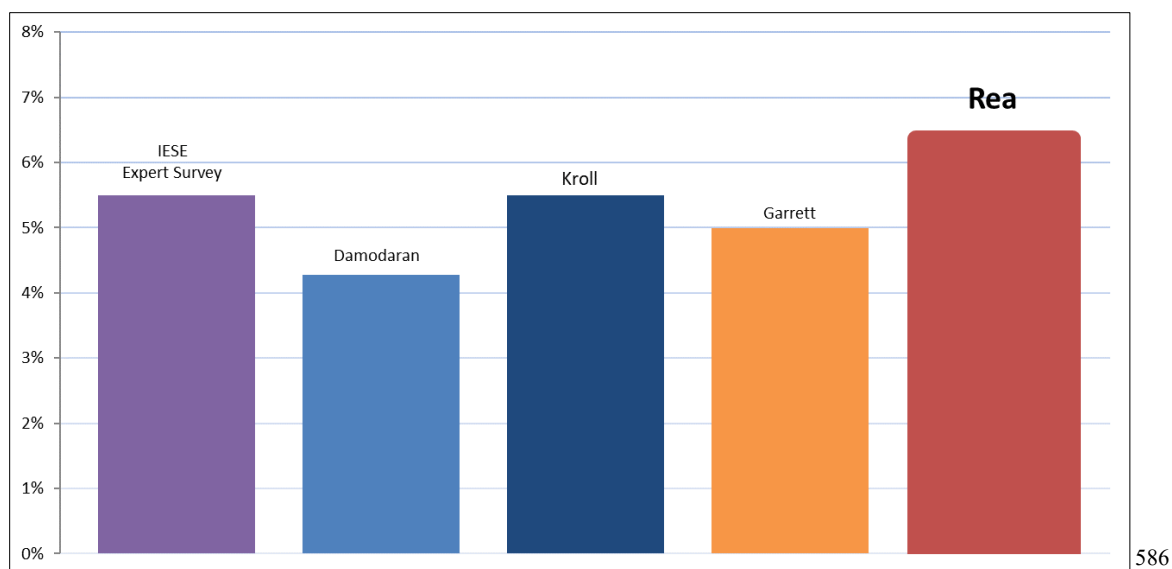
⁵⁸¹ OCA St. 3 at 40.

⁵⁸² OCA St. 3 at 40.

⁵⁸³ OCA St. 3 at 40.

⁵⁸⁴ *Id.*

⁵⁸⁵ OCA St. 3 at 41.



iii. Mr. Rea’s size premium adjustment is unreasonable.

Columbia witness Rea adds a 0.43% size premium adjustment for Columbia to his traditional CAPM results based on his opinion that Columbia’s size relative to the proxy group has an increasing effect to its risk relative to the proxy group.⁵⁸⁷ OCA witness Garrett noted that Columbia should not receive any upward adjustment or consideration to its cost of equity estimate or authorized ROE due to size.⁵⁸⁸ The “size effect” phenomenon was controversial and short-lived.⁵⁸⁹ Adding a 0.43% size premium adjustment for Columbia artificially inflates the cost of equity and should be denied.

⁵⁸⁶ OCA St. 3 at 41.

⁵⁸⁷ OCA St. 3 at 41.

⁵⁸⁸ OCA St. 3 at 42.

⁵⁸⁹ OCA St. 3 at 42-44.

iv. Mr. Rea's additional Risk Premium Model significantly overestimates the cost of equity.

In addition to the CAPM, which is a risk premium model, Columbia witness Rea also conducted another type of risk premium model which ultimately produced the highest result of 11.23% for the Gas LDC Group.⁵⁹⁰ In response, Mr. Garrett testified:

First, Mr. Rea's personal risk premium model adds no marginal value to estimating cost of equity beyond the CAPM – a risk premium mode that resulted in a Nobel Prize in economics and has been used by investors, managers, and analysts around the world for decades. Furthermore, Mr. Rea's personal risk premium method suffers from the same overestimated betas and risk premiums that were present in his traditional CAPM. Finally, Mr. Rea's risk premium model considers, in part, data as old as 1926. This contradicts Mr. Rea's acknowledgement that cost of equity is a forward-looking process. Indeed, the process of estimating the cost of equity is inherently current and forward-looking. It may be helpful to look at a relatively short period in the past to help project future market indicators (such as 30 days of stock prices in the DCF Model, or a few years of market operating earnings for the ERP). However, market data which predates the Great Depression is simply not relevant for estimating Columbia's cost of equity in 2025.⁵⁹¹

As such, the Commission should reject the results of Mr. Rea's risk premium model and focus on the results of the DCF and CAPM models presented in this proceeding.

E. Management Performance Premium

1. Columbia's performance does not merit the granting of a 25 basis point performance management adder.

Columbia's proposed 11.35% return on equity includes a 0.25% upward adjustment for management performance primarily relying upon the testimony of Columbia witness

⁵⁹⁰ OCA St. 3 at 44-45.

⁵⁹¹ OCA St. 3 at 44-45.

Nicole Paloney as support for the performance management adder.⁵⁹² OCA witness Garrett testified that he is not aware of a regulator from another jurisdiction that specifically recognized management performance as having an increasing effect on the authorized ROE.⁵⁹³ OCA witness Garrett further testified as follows:

As discussed in my testimony, the primary driver of the cost of equity and required rate of return is how the market risk impacts individual firms. Managerial performance and the risk of imprudent management is related to firm-specific risks, which are not rewarded by the market because investors can eliminate such risk through diversification of the portfolio, and do not have a material effect on the cost of equity. As investors in competitive firms in the marketplace cannot expect an additional return on equity simply due to prudent managerial performance, the Company as a regulated firm should not receive any premium in addition to an authorized market-based ROE due to prudent managerial performance. OCA witnesses Alexander and Colton also discuss problems with the Company's management performance premium.⁵⁹⁴

In their respective Direct Testimonies, Company witness Rea testifies that the Company has a strong commitment to low-income customers⁵⁹⁵, and Company witness Paloney discusses the Company's claims of "superior" performance and that the Company is "committed to delivering the highest level of customer service to its low income customers."⁵⁹⁶ OCA witnesses Colton and Alexander addressed the Company's claims of "superior" performance. Mr. Colton examined the Company's performance regarding low-income customers, and Ms. Alexander examined the Company's customer service. Mr.

⁵⁹² OCA St. 3 at 56; Columbia Gas St. 8 at 4.

⁵⁹³ OCA St. 3 at 56.

⁵⁹⁴ OCA St. 3 at 56.

⁵⁹⁵ Columbia Gas St. 8 at 4,

⁵⁹⁶ Columbia Gas St. 9. at 4.

Colton and Ms. Alexander both concluded that the Company's initiatives and performance areas do not reflect "superior" performance compared to other NGDCs in Pennsylvania.⁵⁹⁷

Columbia's proposal for a 0.25% upward adjustment for management performance is unjustified, unreasonable, and should be denied by the Commission.

2. Columbia's management performance regarding low-income customers has not been superior and does not merit a management performance adder.

In his review of the Company's claims of "superior" performance, Mr. Colton examined the Company's service quality for low-income customers and its universal service programs. OCA witness Colton testified that Company witness Paloney substantially over-states the Company's role in promoting and providing universal service programs to its low-income customers.

a. LIHEAP Performance

Company witness Paloney specifically cites to Columbia's performance related to its Low-Income Home Energy Assistance Program (LIHEAP) in support of the Company's claim for superior performance for low-income customers and its commitment to low-income customers.⁵⁹⁸ OCA witness Colton testified:

LIHEAP and Crisis, however, are not programs provided by Columbia Gas. They are instead federally-funded programs. Witness Paloney states that "The Company's [Energy Assistance Team] encourages low-income customers to apply for LIHEAP and can assist in completing the application." (Id., at 7). She notes that 15,561 customers received LIHEAP assistance in the 2023-2024 program year.⁵⁹⁹

⁵⁹⁷ OCA St. 5 at 42; OCA St. 6 at 9.

⁵⁹⁸ Columbia St. 9 at 8-9.

⁵⁹⁹ OCA St. 5 at 48.

Moreover, what Ms. Paloney also leaves out of her analysis is that Columbia's LIHEAP and Crisis recipients have been steadily trending downward.⁶⁰⁰ In Table 10 in his Direct Testimony,⁶⁰¹ OCA witness Colton showed that the number of LIHEAP recipients have substantially decreased over the last three program years:

Table 10. No. of LIHEAP and Crisis Recipients and Dollars of LIHEAP and Crisis Grants (OCA-IV-17)				
	LIHEAP CASH	CRISIS	LIHEAP CASH	CRISIS
2022-2023	16,176	3,398	\$6,398,936.66	\$1,904,485.83
2023-2024	15,561	2,630	\$5,830,855.00	\$1,112,887.02
2024-2025	13,991	1,939	\$3,950,821.89	\$845,500.03

Table 10 and the Company's statistics regarding LIHEAP performance demonstrate that even though Columbia claims exemplary performance in this area, Columbia's performance is not, in fact, superior. Mr. Colton testified:

[m]oreover, even looking at the year with the highest LIHEAP participation by Columbia Gas customers (2022-2023, i.e., the 2023 program year), Paloney did not mention that LIHEAP provided benefits to 312,789 households that year. Columbia Gas LIHEAP recipients represented only five percent (5%) of the total number of LIHEAP recipients statewide (16,176/312,789) and less than two percent of the total LIHEAP benefits distributed (\$6,398,937/ \$334,411,760 = 0.019). While Ms. Paloney argues that Columbia exhibits "strong performance" because 2,630 of the Company's customers received Crisis assistance in the 2024 LIHEAP program year, again, that number should be placed in context. Again using the higher number from the 2023 program year (3,398), Columbia Gas customers received only 3.4% of the total 98,771 LIHEAP Crisis grants delivered statewide. This occurred even though only Peoples Gas and PECO (Gas) had substantially more nonpayment disconnections of Confirmed Low-Income customers than did Columbia Gas.⁶⁰²

⁶⁰⁰ OCA St. 5 at 48.

⁶⁰¹ OCA St. 5 at 48.

⁶⁰² OCA St. 5 at 48-49.

Although in Rebuttal Testimony, Ms. Paloney claims that the Company received virtually the same number of LIHEAP grants in 2024-2025 as in 2023-2024 (within 267 grants).⁶⁰³ Ms. Paloney does not address the fact that there has been a clear downward trend for receipt of LIHEAP by Columbia Gas customers from 2017 through 2025.⁶⁰⁴ Columbia has not met its burden to demonstrate that its claimed performance with respect to obtaining LIHEAP assistance for its low-income customers is exemplary.

b. Columbia Gas’s efforts to serve its low-income customers have not been exemplary as demonstrated by the BCS Universal Services report.

OCA witness Colton examined Columbia witness Rea’s and Paloney’s claims of “superior” service to low-income customers by reviewing Columbia’s performance in comparison to other Pennsylvania NGDCs in the annual Bureau of Consumer Services Universal Service Programs and Collections Performance reports (BCS report). As Mr. Colton noted in his Direct testimony, the BCS report states that when the legislature adopted the mandate for universal service programs, “the General Assembly wanted to ensure that...natural gas service remain universally available to all customers in the state. Both Acts contain provisions that require utilities to establish programs to maintain affordable electric and gas service for low-income customers.”⁶⁰⁵ The BCS report measures each of the natural gas utility’s performance areas in meeting the statutory objectives. In

⁶⁰³ Columbia St. 9-R at 3.

⁶⁰⁴ OCA St. 5SR at 1-2, Figure 1.

⁶⁰⁵ OCA St. 5 at 51, quoting the 2023 BCS annual report at 3 and citing the Natural Gas Choice and Competition Act, 66 Pa. C.S. § 2202.

key performance areas including CAP payment rate, the dollars which each utility forgives through their respective CAP each year, termination rates and reconnection rates, and CAP credit in comparison to CAP bills, Columbia’s performance has consistently been lower than its natural gas utility counterparts in Pennsylvania.

Mr. Colton examined the “payment rate” of each utility’s CAP. The CAP Payment Rate (in full) is calculated the same for each of the utilities and “is calculated by dividing the total number of full monthly CAP payments made by the total number of monthly CAP bills rendered.”⁶⁰⁶ He found that Columbia Gas has been “dead last in the CAP payment rate each year.”⁶⁰⁷ Table 11⁶⁰⁸ provided:

Table 1. CAP Payment Rate by Year (2021 – 2023) ⁶⁰⁹ (Penn Natural Gas Distribution Companies)			
	2021	2022	2023
Columbia Gas	52.5%	44.7%	46.6%
NFG	71.5%	72.7%	66.6%
PECO	70.2%	70.2%	70.8%
Peoples	53.1%	55.9%	58.7%
PGW	58.2%	64.0%	60.2%
UGI	89.6%	92.0%	79.7%
State average	62.8%	64.1%	62.4%

⁶⁰⁶ OCA St. 5 at 49, citing 2023 BCS annual report at 66.

⁶⁰⁷ OCA St. 5 at 50.

⁶⁰⁸ OCA St. 5 at 50, Table 11.

⁶⁰⁹ *Id.* at 67.

In Rebuttal Testimony, Ms. Paloney erroneously claims that the CAP payment rate reports on customer payments only.⁶¹⁰ As OCA witness Colton clarifies in his Surrebuttal Testimony, Ms. Paloney confuses two metrics: Percentage of CAP Dollars Paid by Natural Gas CAP Customers with CAP Payment Rate. The former does not account for LIHEAP payments and is not the metric used by Mr. Colton in his analysis. Mr. Colton examines the metric that measures the percentage of CAP bills that were paid in full by CAP participants.⁶¹¹ The CAP Payment Rate is a better metric for evaluation of management performance because as OCA witness Colton testified:

This metric does not work under the limitation of whether a bill is paid by LIHEAP or out-of-pocket by the customer. Rather than measuring what portion of a CAP bill is paid out-of-pocket from customer funds, it measures what percentage of CAP bills were paid in full. In assessing whether a bill has been paid in full, Columbia Gas does not consider the source of the payment. Whether the dollars of payment originate from a federal program such as LIHEAP, a private hardship fund, or from the customer's own pocket, a bill is either paid in full or it is not.⁶¹²

As OCA witness Colton summarized, the facts demonstrate that “Columbia has the worst performance of any natural gas utility. The Columbia Gas performance (46.6% is substantially below the statewide natural gas average (62.4%).”⁶¹³ Columbia has not demonstrated that it has superior performance in this area.

⁶¹⁰ Columbia St. 9-R at 4-5.

⁶¹¹ OCA St. 5SR at 3.

⁶¹² OCA St. 5SR at 3.

⁶¹³ OCA St. 5SR at 3.

Second, Mr. Colton also compared Columbia's performance for "the dollars which each utility forgives through their respective CAP each year." OCA witness Colton testified:

[a]ccording to the most recent BCS report, in 2023, Columbia Gas had an average annual forgiveness of \$19. That was the lowest amount of forgiveness of any of Pennsylvania's natural gas utilities. The next lowest (PECO Gas) was \$29. The statewide average annual forgiveness in 2023, however, was \$115. The low forgiveness was not attributable to a lower average arrears by Columbia's Confirmed Low-Income customers. In 2023, the average arrears for a Confirmed Low-Income customer of Columbia Gas was \$945.16. This average Confirmed Low-Income arrears was higher than every other Pennsylvania natural gas utility other than PECO Gas. Indeed, the average Columbia Gas Confirmed Low-Income arrears (\$945.16) was nearly \$100 higher than the average natural gas Confirmed Low-Income arrears (\$851.30).⁶¹⁴

Again Columbia's performance for the annual arrearage forgiveness is substantially below the areas of performance of other Pennsylvania natural gas utilities, and like with the CAP payment rate is the lowest in the Commonwealth.

Columbia witness Paloney attempted to explain the low arrearage forgiveness in 2023 as due to an accounting change.⁶¹⁵ She testified that the performance from 2021, 2022, and 2023 is not substantially difference from the performance of other natural gas utilities. However, her testimony does not present the complete picture, and even with the aberration of 2023, the Company data does not support her conclusion. OCA witness Colton presented Figure 2 in his Surrebuttal Testimony which demonstrates that Columbia

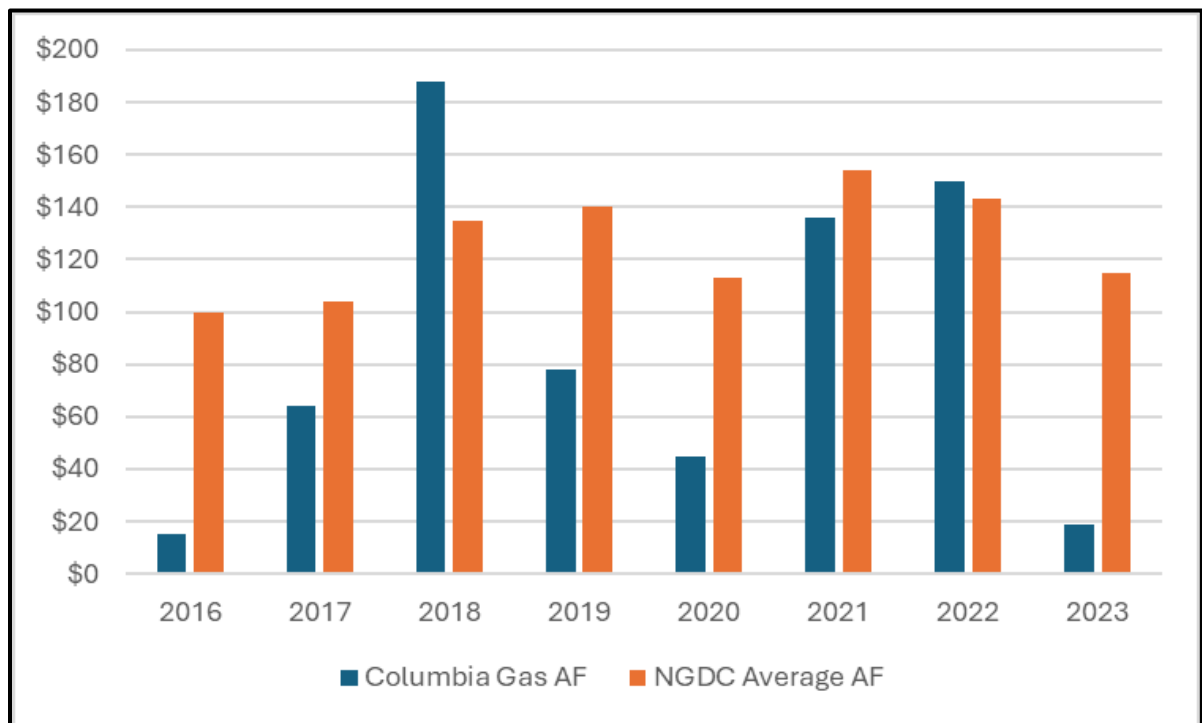
⁶¹⁴ OCA St. 5 at 50-51.

⁶¹⁵ Columbia St. 9 at-R at 6.

routinely forgives substantially fewer arrears than other Pennsylvania natural gas utilities.

Figure 2⁶¹⁶ provides:

**Figure 1. Columbia Gas Arrearage Forgiveness (AF) by Year vs.
Statewide NGDC Arrearage Forgiveness by Year**



The low amount of arrears forgiven relative to other natural gas utilities in Pennsylvania is not because Columbia customers carry low arrears. In fact, the low-income customers for Columbia carry substantially higher arrears than other Pennsylvania natural gas utilities as discussed above.⁶¹⁷

Third, Mr. Colton examined the Company's termination rates and reconnection rates in comparison to the other Pennsylvania natural gas utilities and found that

⁶¹⁶ OCA St. 5SR at 5.

⁶¹⁷ OCA St. 5SR at 5.

Columbia's performance fell significantly short of the statewide average for reconnections.⁶¹⁸ OCA witness Colton testified:

BCS reports that in 2023, while Columbia Gas had an average of 10,305 Confirmed Low-Income customers in debt, it terminated a total of 5,974 Confirmed Low-Income customers. For every 100 Confirmed Low-Income customers in debt, in other words, Columbia disconnected service to 60 Confirmed Low-Income accounts. Making this performance even worse is the fact that BCS reports that Columbia Gas reconnected only 2,936 Confirmed Low-Income customers once they had been disconnected (49%).⁶¹⁹

In contrast to Columbia's performance, the statewide average reconnection rate was 76.6% for Confirmed Low-Income customers of natural gas utilities versus Columbia Gas's reconnection rate of 49.1%. In fact, Columbia's reconnection rate was the lowest for all of the natural gas utilities. The next lowest reconnection rate was for UGI Gas, 74.7%. The highest reconnection rate was for PECO Gas, at 90.8%.⁶²⁰ As OCA witness Colton testified "no other natural gas utility in Pennsylvania has a reconnection rate for Confirmed Low-Income customers that falls below 70%, let alone one that falls below 50% as does Columbia Gas."⁶²¹

In Rebuttal Testimony, Columbia Gas witness Paloney attempted to explain the low reconnection rate and attribute it to customers who move and are reconnected at a new address.⁶²² As OCA witness Colton testified, this would equally apply to the data presented for other natural gas utilities, and does not explain why the performance of Columbia is so

⁶¹⁸ OCA St. 5 at 51-52.

⁶¹⁹ OCA St. 5 at 51 (footnotes omitted).

⁶²⁰ OCA St. 5 at 52.

⁶²¹ OCA St. 5 at 52.

⁶²² Columbia St. 9-R at 6-7.

much poorer than the performance of every other natural gas utility.⁶²³ OCA witness Colton testified:

Even more problematic, however, is that Ms. Paloney does not seek to quantify the extent to which customers move after a disconnection and are then reconnected albeit at a different address. Data reported by Columbia Gas in its Cold Weather Survey to the Commission, however, demonstrates the extent to which the circumstances speculated by witness Paloney do not arise.⁶²⁴

In order to assess this claim, Mr. Colton examined the Cold Weather Survey which provides data on the number of units that were “vacant” at the time of the survey. If the housing unit was not listed as “vacant” in the survey, then Ms. Paloney’s speculation would not be correct. Based on the Cold Weather Survey results, Mr. Colton concluded that Ms. Paloney’s assertions were not accurate. Mr. Colton testified that:

[a]t the time of the 2024 Cold Weather Survey, only 12% of the disconnected units were vacant, while in 2023, only 11% were. This is not to say that all of those customers who had vacated their homes had moved and been reconnected elsewhere. However, it is to say, that unless someone had moved, irrespective of whether they have been connected elsewhere, Ms. Paloney’s explanation would not apply.⁶²⁵

Fourth, Mr. Colton examined Columbia witness Paloney’s claim that their superior management can be found in the fact that “[t]he Commission’s 2023 Universal Service Programs and Collections Performance Report lists the Company as having the highest CAP credit per CAP customer of all gas utilities, thereby providing the most benefits for its CAP customers.”⁶²⁶ However, Ms. Paloney’s statements only tell a portion of the story.

⁶²³ OCA St. 5SR at 6.

⁶²⁴ OCA St. 5SR at 6.

⁶²⁵ OCA St. 5SR at 7.

⁶²⁶ Columbia St. 9 at 12; OCA St. 5 at 53.

While Columbia does have a higher CAP credit, Columbia's average bills were also higher than all but two other utilities in the state. OCA witness Colton testified:

Paloney's conclusion, however, does not flow from that fact that she cites. I do not dispute that Columbia Gas provided a higher CAP credit than any other Pennsylvania natural gas utility. What Columbia witness Paloney did not cite, however, is the fact that despite this high credit, Columbia's CAP participants were not better off than the CAP participants of other natural gas utilities. BCS also reports the average CAP bill for each utility. As can be seen, even though Columbia Gas may provide a higher CAP credit, that higher credit does not result in lower CAP bills. Indeed, even though Columbia provides the highest CAP credit of Pennsylvania's natural gas utilities, only PGW and UGI Gas have higher monthly CAP bills in the state.⁶²⁷

Table 13⁶²⁸ in Mr. Colton's testimony presents a different picture of Columbia's performance by comparing the average annual CAP credit with the average monthly CAP bill:

⁶²⁷ OCA St. 5 at 54.

⁶²⁸ OCA St. 5 at 53, Table 13.

Table 2. Average CAP Bills and Average CAP Credits (2023) (Penn Natural Gas Distribution Companies)		
	Average Annual CAP Credit ⁶²⁹	Average Monthly CAP Bill ⁶³⁰
Columbia Gas	\$1,099	\$62
NFG	\$291	\$59
PECO	\$464	\$45
Peoples	\$613	\$57
PGW	\$925	\$64
UGI	\$721	\$69
State average	\$771	\$60

The higher CAP credit is not a reflection of superior management, but instead a reflection that Columbia’s bills are so much higher than the bills of other Pennsylvania natural gas utilities.⁶³¹ OCA witness Colton testified that “[i]t is hardly evidence of exemplary Columbia Gas management to note that the Company’s monthly heating bills are nearly \$60 higher than the next highest utility (Columbia Gas: \$289.10 vs. PGW \$232.14).”⁶³²

Fifth, OCA witness Colton also examined the payment outcomes for Columbia’s CAP using the same 2023 BCS report that Columbia witness Paloney cited. OCA witness Colton testified:

⁶²⁹ OCA St. 5 at 53, citing 2023 Bureau of Consumer Services Universal Services and Collections Performance Report, at 64 <https://www.puc.pa.gov/media/3195/2023-universal-service-report-final.pdf> (Last accessed August 22, 2025)

⁶³⁰ *Id.* at 61.

⁶³¹ OCA St. 5 at 54.

⁶³² OCA St. 5 at 54.

[t]hat BCS report publishes the total dollars of CAP bills along with the total dollars of CAP payments on an annual basis. According to the BCS report, in 2023, while Columbia rendered \$18,529,098 in CAP bills, it collected \$12,635,348 in CAP payments (68%). Other natural gas utilities did much better, with PECO (Gas) collecting 87% of what is billed to CAP customers. Peoples collecting 79%, and UGI Gas collecting 76%.⁶³³

Columbia's collection rate was again below its peers.

In response to Ms. Paloney's claim that Columbia demonstrates superior management because the average CAP bill for Columbia customers has been consistently lower than the average CAP bill for Pennsylvania natural gas utilities. OCA witness Colton testified:

Her conclusion, however, does not follow from her premise. All that Ms. Paloney's data shows is that, historically, Columbia has had a different mix of CAP participants by income than other Pennsylvania natural gas utilities. In contrast, in 2023, the year I used for comparison, the mix of CAP participants by income between Columbia Gas and other state natural gas utilities was relatively constant. While 74% of participants fell in the bottom two tiers of FPL in 2023, the statewide average of CAP falling into those bottom two tiers was 73.5%.⁶³⁴

Sixth, OCA witness Colton reviewed Columbia witness Paloney's citation to the Company's CARES (Customer Assistance Referral and Evaluation Services) program in support of the Company's assertions regarding its commitment to low-income customers.⁶³⁵ However, the OCA submits that the Company's assertions regarding its CARES program are overstated. OCA witness Colton testified:

⁶³³ OCA St. 5 at 55.

⁶³⁴ OCA St. 5SR at 8, citing 2023 Bureau of Consumer Services Universal Services and Collections Performance Report, at 59 <https://www.puc.pa.gov/media/3195/2023-universal-service-report-final.pdf> (Last accessed August 22, 2025)

⁶³⁵ Cite.

BCS reports each year the total dollars of direct benefits (including LIHEAP) that each Pennsylvania natural gas utility generates for its CARES participants. According to BCS, in 2023, Columbia Gas in its administrative dollars for CARES and generated \$40,933 in direct benefits applied to CARES accounts (including LIHEAP) in 2023.⁶³⁶

As OCA witness Colton noted, only NFG had fewer benefits applied to CARES participants. Moreover, 2023 was not an aberration. In 2022, Columbia generated only \$30,967 in direct benefits to CARES accounts and in 2021, the total was \$30,499.⁶³⁷

In response to Columbia witness Paloney's claim that the CARES team is "trained to assist and complete CAP, LIHEAP and hardship fund applications for our most vulnerable customers."⁶³⁸ OCA witness Colton also examined the Company's intra-company collaboration regarding universal services. Mr. Colton testified "Columbia Gas, however, reports the number of CARES customers which participate in multiple programs each year."⁶³⁹ Mr. Colton found that the Company worked with 2,311 CARES customers over the four-year period between 2021 and 2024, but had very poor cross-program performance within the Company. He testified that Columbia's cross-enrollment results were to:

- Enroll a total of two (2) customers in both CARES and LIURP over the most recent four-year period;
- Enroll a total of 25 customers in both CARES and CAP over the most recent four-year period (with number declining each year);

⁶³⁶ OCA St. 5 at 55 (footnotes omitted).

⁶³⁷ OCA St. 5 at 56.

⁶³⁸ Columbia St. 9 at 8.

⁶³⁹ OCA St. 5 at 56.

- Enroll a total of one (1) customer in CARES, LIURP and CAP, and only one (1) in CARES, LIURP and the Company's hardship fund, over the most recent four-year period.
- Enroll a total of only six (6) customers in CARES, CAP and the Hardship Fund over the most recent four year period.⁶⁴⁰

As OCA witness Colton testified, “[t]he best cross-program performance by the Columbia Gas Team...involves the CARES Team cross-enrolling a total of fewer than 100 of the total 2,311 CARES customers in the Company's Hardship Fund over the most recent four year period.”⁶⁴¹

Over the four-year period, as presented in Table 15,⁶⁴² he found that the problem was compounded:

Table 3. Participants in Multiple Programs: CARES Plus Others (OCA-04-026)				
	2021	2022	2023	2024
Customers referred to CARES	779	540	484	508
CARES and LIURP	1	1	0	0
CARES and CAP	9	7	5	4
CARES and Hardship Fund	27	24	22	21
CARES, LIURP and CAP	0	1	0	0
CARES, LIURP and Hardship Fund	0	1	0	0
CARES, CAP and Hardship Fund	3	2	1	0
CARES, LIURP, CAP and Hardship Fund	0	1	0	0

⁶⁴⁰ OCA St. 5 at 57.

⁶⁴¹ OCA St. 5 at 57.

⁶⁴² OCA St. 5 at 57, Table 15.

A similar lack of cross-program coordination occurs regarding the Hardship Fund. OCA witness Colton testified that “[s]etting aside 2021 data as reflecting unusual circumstances affected by COVID, in the three years 2022 through 2024, fewer than 50 Columbia Gas customers participated in both LIURP and the Hardship Fund, while fewer than 70 participated in both CARES and the Hardship Fund.”⁶⁴³ He testified that this lack of cross-program intracompany coordination occurs even though the following occurs:

- CAP participants have paid fewer than half of their CAP bills;
- For every 100 Confirmed Low-Income Columbia Gas customers in debt, Columbia disconnected service to 60 Confirmed Low-Income accounts.
- Columbia Gas reconnected fewer than half of the Confirmed Low-Income customers once they had been disconnected (49%).⁶⁴⁴

While Company witness Paloney asserts that this data is incomplete because it is in addition “to customer that receive specialized payment plans and individual case management through CARES” and that the program offers other services.⁶⁴⁵ As OCA witness Colton testified, it certainly identifies that Ms. Paloney’s testimony is in error when she specifically cited in her Direct Testimony that CARES is providing a “combination of the three programs [LIHEAP, Crisis, hardship funds]” as evidence of superior management.⁶⁴⁶ The facts do not support her assertions that there is a demonstration of superior management.

⁶⁴³ OCA St. 5 at 57-58.

⁶⁴⁴ OCA St. 5 at 58.

⁶⁴⁵ Columbia St. 9-R at 10.

⁶⁴⁶ Columbia St. 9 at 17; OCA St. 5SR at 9.

Seventh, Columbia witness Paloney also cites to the Hardship Fund and the \$150,000 contribution to the Dollar Energy Fund as evidence of exemplary management.⁶⁴⁷ OCA witness Colton testified:

[w]hat she does not testify to is the fact that, as reported in the Company's annual report to BCS, the Columbia Gas contribution to its Hardship Fund has been set at \$150,000 per year going back to at least 2017. In contrast, according to the PUC's annual rate comparison report, the Columbia Gas average heating bill in 2017 was \$184.63 as compared to its 2024 bill of \$289.10. While the Company's bills increased 60%, in other words, the Company's support of its Hardship Fund did not increase at all.⁶⁴⁸

Nor does the Company pursue any innovative fundraising, provide any administrative contributions, and in the last four years, the Company has raised no money from companies other than itself, made no contributions from settlements or fines, and has raised no money from "other sources" for the Hardship Fund.⁶⁴⁹ Columbia's ratepayer/employee contribution have remained the same at \$375,000 per year since 2017 as well.⁶⁵⁰

In Rebuttal testimony, Ms. Paloney overstates Columbia's efforts to raise money for its Hardship Fund. She claims that the Company secured pipeline credits and refunds in the amount of \$375,000 per year when available, but those funds were not reported in the BCS report for the four-year period from 2021 through 2023.⁶⁵¹ She also asserts that the Company currently has \$1 million in Hardship Funds as "responsible stewardship."⁶⁵²

⁶⁴⁷ OCA St. 5 at 59.

⁶⁴⁸ OCA St. 5 at 59.

⁶⁴⁹ OCA St. 5 at 59.

⁶⁵⁰ *Id.*

⁶⁵¹ Columbia St. 9-R at 11.

⁶⁵² Columbia St. 9-R at 11.

Mr. Colton did not agree that having \$1 million in Hardship Funds was “responsible stewardship.” OCA witness Colton testified:

[a]ccording to the Columbia Gas reports to BCS (OCA-04-26), Columbia Gas has raised a total of \$1,506,238 in hardship fund contributions in 2022 through 2024. To have “more than \$1,000,000” of that remaining unspent in a time period when the average Confirmed Low-Income customers of Columbia Gas reached \$945.16 in 2023; when Columbia Gas disconnected 12,254 Confirmed Low-Income customers, with an average arrears of \$1,191 at the time of disconnection; and when 9,159 of the 18,215 deferred payment arrangements for Confirmed Low-Income Customers defaulted, is not “responsible stewardship,” and is hardly data to be cited as support for any claim of exemplary management.⁶⁵³

In sum, OCA witness Colton identified numerous additional factors which demonstrate that Columbia has not provided superior service to its low-income customers and that the Company reaches only a little over a quarter of its CAP customers. Mr. Colton testified:

Columbia Gas has enrolled a fraction of its estimated low-income customers in its CAP and that enrollment is declining. In 2023, while Columbia had an estimated 91,415 low-income customers, it had enrolled only 23,875 (26.1%) of those estimated low-income customers into the Company’s CAP. In 2024, while the number of estimated low-income customers increased to 91,881, the number of average monthly CAP participants had declined to 21,391 (23.3%).⁶⁵⁴

Columbia witness Paloney attempts to deflect by questioning the reliability of the Commission-prescribed methodology for calculating the number of Confirmed Low-Income customers. The OCA notes that the methodology used is the methodology relied upon by BCS, by Penn State for its analysis, and by all of the other NGDCs.⁶⁵⁵ OCA

⁶⁵³ OCA St. 5SR at 9.

⁶⁵⁴ OCA St. 5 at 60-61.

⁶⁵⁵ OCA St. 5SR at 10-11.

witness Colton testified that the flaw is in Columbia’s analysis, not the BCS methodology, of what the true Confirmed Low-Income population is. Mr. Colton testified:

[w]hen asked how Columbia Gas confirms the low-income status of customer, the Company responded that “The Company ‘confirms’ the low income status of its customers through self-declaration of income at or below 150% of the federal poverty income guidelines, receipt of LIHEAP assistance, or enrollment in the Company’s CAP.” (OCA-VIII-04). For witness Paloney to argue that it enrolls 30% of its Confirmed Low-Income customers into CAP, without acknowledging that CAP participation is one of the three ways in which they “confirm” low-income status in the first instance, presents a hopelessly circular argument. Even Columbia Gas acknowledges that, in 2024, of the 74,767 customers the Company had identified as Confirmed Low-Income, 35, 351 (47% were either CAP participants, or LIHEAP recipients, or both. (CAUSE-PA-XIV-1). The Company does not identify Confirmed Low-Income customers and then enroll those customers into CAP. It instead enrolls customers into CAP and then labels those CAP participants as “Confirmed Low-Income.”⁶⁵⁶

Moreover, Columbia also has three times more nonpayment disconnections for Confirmed Low-income customers than for residential customers as a whole.⁶⁵⁷ OCA witness Colton testified:

In 2023, for example, Columbia had a termination rate (i.e., number of disconnections per 100 customers) of 2.5 for residential customers and a termination rate for Confirmed Low-Income customers of 8.3 (a rate 3.32 times higher than the residential rate). This termination rate has remained constant over the past several years. In 2022, the residential termination rate was 2.8% compared to a Confirmed Low-Income rate of 8.7. In 2021, the residential termination rate was 2.4%, compared to the Confirmed Low-Income rate of 8.0.⁶⁵⁸

⁶⁵⁶ OCA St. 5SR at 11.

⁶⁵⁷ OCA St. 5 at 61.

⁶⁵⁸ OCA St. 5 at 61.

Aas discussed *supra*, a disconnected Confirmed Low-Income customer is less likely by far to be reconnected as a Columbia Gas customer than for any other utility in Pennsylvania.⁶⁵⁹ Columbia's reconnection rate was 49.1% in 2023, and in 2024, it was only slightly higher at 51.8%.⁶⁶⁰

Instead of enrolling Confirmed Low-Income customers in CAP, Columbia has elected to seek payment arrangements as a means to address low-income arrears. OCA witness Colton testified that:

Columbia does not adequately use deferred payment arrangements as a means to address low-income arrears. Even though Columbia entered into 14,659 payment arrangements with Confirmed Low-Income customers in 2023, it reported that it had 7,422 "payment-troubled" Confirmed Low-Income customers that year. Given that "payment-troubled" is a term-of-art (defined to be a customer one or more defaulted payments in the past year), for every 100 Confirmed Low-Income payment arrangements entered into by Columbia Gas, the Company experiences more than 50 defaulted arrangements.⁶⁶¹

Columbia substitutes collection efforts over enrollment of non-CAP Confirmed Low-Income customers into CAP. OCA witness Colton concluded:

rather than enrolling Company customers which Columbia Gas has a reasonable basis to believe to be low-income into CAP, Columbia continues to resort to collection efforts directed towards its non-CAP Confirmed Low-Income customers even when those collection efforts have been proven to be ineffective.

Mr. Colton noted that one impact of this ineffective management of low-income debt is the fact that the Company has a gross write-off ratio for Confirmed Low-Income

⁶⁵⁹ OCA St. 5 at 61; Cite.

⁶⁶⁰ OCA St. 5 at 62.

⁶⁶¹ OCA St. 5 at 62.

customers that is more than three times higher than the gross write-off ratio for residential customers as a whole (6.8% Confirmed Low-Income vs. 2.0% residential in 2023).⁶⁶² Columbia witness Paloney attempts to rebut Mr. Colton's assessment of the gross write-off ratio.⁶⁶³ However, the Company examines the wrong metric, and in particular, she responds to a metric that Mr. Colton did not raise. OCA witness Colton testified:

[t]he question when considering how effectively Columbia Gas addresses the payment difficulties of its low-income customers is not how Columbia Gas compares to other natural gas utilities, but rather how the low-income customers of Columbia Gas compare to the non low-income customers of Columbia Gas. That is, and a fact that witness Paloney does not seek to dispute, is that Columbia Gas has one of the highest ratios of low-income to non-low-income write-off percentages in Pennsylvania. The Columbia Gas ratio is substantially higher than the statewide natural gas average. Only two natural gas utilities (PECO, NFG) have higher ratios.⁶⁶⁴

OCA witness Colton identified lessons and improvements that could be made to improve the Company's management performance. First, the Company should use its universal service program more effectively to address the nonpayment problems. As he noted, "[t]he use of universal service programs can also operate to help Columbia Gas manage the costs of payment difficulties which are passed on to all other ratepayers."⁶⁶⁵ It is clear, however, from the empirical data presented that the Company has not demonstrated superior management performance with respect to its low-income customers and has important areas that should be addressed for improvement.

⁶⁶² OCA St. 5 at 62-63 (footnote omitted).

⁶⁶³ Columbia St. 9 at 14.

⁶⁶⁴ OCA St. 5SR at 14.

⁶⁶⁵ OCA St. 5 at 63.

c. Columbia's customer service performance also fails to achieve superior performance.

In her review of the Company's claims of "superior" performance, Ms. Alexander examined the Commission's annual Quality of Customer Service reports on customer service performance for the customer call center, meter reading, billing timeliness, customer satisfaction survey responses, and responses to customer disputes.⁶⁶⁶ The reports compare the performance of Pennsylvania's largest natural gas utilities. For her analysis Ms. Alexander reviewed the 2023 annual Quality of Customer Service report and the Company's 2024 results obtained through discovery. She also reviewed the quarterly UCARE (Utility Customer Activities Report and Evaluation) that presents data on complaints and payment arrangements handled by the Commission's Bureau of Consumer Services (BCS).⁶⁶⁷

In response to Columbia witness Kempic's Rebuttal Testimony that this rate case and the performance management adder are not about "rewarding NiSource shareholders" but about safety and the remaining prone to fail pipe.⁶⁶⁸ The OCA disagrees with the characterization that the performance management adder is about additional return on rate base and profit to the shareholders, not about safety. As OCA witness Alexander testified "Mr. Kempic is incorrect as to the purpose of this increase in the rate of return for management performance."⁶⁶⁹ OCA witness Alexander disagreed with any increase in the

⁶⁶⁶ OCA St. 6 at 10.

⁶⁶⁷ OCA St. 6 at 10.

⁶⁶⁸ Columbia St. 1-R at 19 (footnotes omitted).

⁶⁶⁹ OCA St. 6 at 3.

rate of return beyond what is necessary to meet the Company's statutory obligations. She testified:

[a]ny increase in the rate of return beyond that necessary to meet the Company's statutory obligations results in higher rates for Columbia's customers and higher returns to Columbia's shareholders. Mr. Patel on behalf of I&E calculated that Columbia's higher rate of return would result in a rate increase of over \$7 million compared to its proposed rate of return based on standard ratemaking calculations. Either Mr. Kempic wants to raise rates and shareholder profits to continue its regulated and necessary work to maintain its distribution system (the costs and plans for which are already reflected in Columbia's proposed revenue requirement without any management incentive) or Columbia wants a "reward" that would increase what is otherwise necessary for just and reasonable rates. My description of what Columbia is proposing is accurate.⁶⁷⁰

Columbia witness Paloney testified that Columbia's 2023 performance "as reflected in the UCARE report with regards to the five major natural gas companies, is among the best in most categories across the Pennsylvania gas utility industry."⁶⁷¹ However, Ms. Alexander's testimony demonstrated that Ms. Paloney's metrics were selective, and that she ignored areas that reflected average or below average or the trend in deterioration in several areas.⁶⁷² In particular, OCA witness Alexander reviewed the Company's call center performance, customer satisfaction surveys, and the Company's claim for success pursuant to a JD Power survey.

i. Call Center Performance

Ms. Alexander reviewed the Company's Call Center performance and found that its performance was not "superior" as claimed by Columbia. The call center is an essential

⁶⁷⁰ OCA St. 6 at 3 (footnotes omitted).

⁶⁷¹ Columbia St. 9 at 20; OCA St. 6 at 10.

⁶⁷² OCA St. 6 at 10.

function. It is the only means by which customers can speak to the Company about their service needs, file a complaint, ask for a payment plan, otherwise engage in negotiations since there is no in-person office available in the service territory. As OCA witness Alexander testified “[t]he Company operates its customer call center with NiSource employees who operate 100% virtually to serve the customers of all of its gas distribution companies, including Pennsylvania.”⁶⁷³ The OCA recommends that the evidence does not justify any increased profits in Columbia’s rate of return. Any rate increase approved in this proceeding should require Columbia to maintain its 2024 performance at a minimum during the rate effective year to avoid the potential that increased rates are not accompanied by a lack of attention and commitment in this area once the rate case is concluded.

For its Call Center, Columbia did not achieve its own internal objective of 80% of the calls answered within 30 seconds.⁶⁷⁴ The Company does not have an objective regarding call abandonment. OCA witness Alexander testified:

Columbia’s annual average percent of calls answered within 30 seconds was the lowest (worst) of all Pennsylvania NGDCs from 2021-2023 (74%, 74%, and 73% respectively). The other NGDCs reported better results of 80% or higher for most years (higher percentage of calls answered within 30 seconds). The only NGDC that reported lower results than Columbia for any year was the UGI Gas’ 2022 results of 73%. With regard to the annual average call abandonment rate (referring to the customers who hang up after entering the queue to speak to a representative), Columbia’s percentage rate for 2021-2023 (7%, 7%, and 6%, respectively) was worse (higher) than two of the four other NGDCs and in 2023 was the highest of the other NGDCs with the except of UGI-Gas at 7%. In 2024 Columbia improved its call center

⁶⁷³ OCA St. 6 at 11.

⁶⁷⁴ OCA St. 6 at 12.

performance results and reported 83% of calls answered within 30 seconds with a 2.25% call abandonment rate.⁶⁷⁵

Ms. Alexander testified regarding her concerns about the customer call center performance, in particular about the Company's historic call center performance. OCA witness Alexander testified:

First, Ms. Paloney ignores this historical call center performance information in her testimony. Second, these results do not reflect "superior" or "high level" customer service. The results indicate below average performance in 2021-2023. Finally, there is measurable improvement in 2024 compared to 2023, a result that reflects my key recommendation.⁶⁷⁶

In Confidential Exhibit BA-2, OCA witness Alexander provides the Call Center performance for 2022 through March 2025. **BEGIN CONFIDENTIAL** [REDACTED]

[REDACTED]
END CONFIDENTIAL⁶⁷⁷

Ms. Paloney argues that the Company is not required by statute to benchmark its performance to its peers, but as Ms. Alexander correctly notes this statement is inconsistent with Ms. Paloney's Rebuttal Testimony to Mr. Colton wherein she routinely seeks to compare Columbia's low-income performance against other utilities and her comparison in Direct of the Company's customer service performance and historical performance.⁶⁷⁸

The comparison to other Pennsylvania peers is important. OCA witness Alexander:

⁶⁷⁵ OCA St. 6 at 11-12. OCA witness Alexander attached to her Direct Testimony a Confidential Exhibit BA-2 which provides the current call center performance for 2022 through March 2025.

⁶⁷⁶ OCA St. 6 at 12.

⁶⁷⁷ OCA St. 6 (CONFIDENTIAL VERSION) at Confidential Exh. BA-2.

⁶⁷⁸ Columbia St. 9-R at 20; Columbia St. 9 at 3; OCA St. 6 at 3-4.

[t]he comparison to Columbia’s performance to its peers in Pennsylvania allows a consideration of performance with the same regulatory expectations, similar economic impacts that vary year to year, and data that is gathered and evaluated by the Commission to ensure that it is accurate and reflects the Commission’s directive. Under these circumstances it is fair to point to differences or trends since the performance data is presented in a uniform manner and reflects similar circumstances (such as how the COVID pandemic impacted utility performance and how these utilities responded in subsequent years). While Ms. Paloney relies on the UCARE and Customer Activity reports to justify her conclusions about Columbia’s performance, I do as well. The difference is that she has selected data that bolsters her conclusions and I have pointed out data in these same reports that she has ignored or failed to properly consider. Her attempt to deflect my use of this same performance data by now arguing that performance among Columbia’s Pennsylvania peers is no longer the primary basis for considering management effectiveness or to justify her claim of “superior” performance is not credible.”⁶⁷⁹

Ms. Paloney acknowledges that the performance of the center is just one of many factors to be considered but objects to Ms. Alexander’s recommendation that the Commission should consider it in their evaluation of rate increase request.⁶⁸⁰ However, Ms. Paloney’s Direct Testimony praised its call center performance, and as Ms. Alexander testified, “[she] cannot have it both ways.”⁶⁸¹ Ms. Alexander “documented Columbia’s below average performance in 2021-2023 from the same UCARE report that Ms. Paloney relied upon to cherry pick results that favored her claim of ‘superior’ performance.”⁶⁸² While the Company’s performance is now similar to other natural gas utilities based on currently available information, “that does not demonstrate exemplary performance such

⁶⁷⁹ OCA St. 6 at 4-5.

⁶⁸⁰ Columbia St. 9-R at 16; OCA St. 6 at 6.

⁶⁸¹ OCA St. 6 at 6.

⁶⁸² OCA St. 6 at 6-7.

that a higher return should be awarded.”⁶⁸³ As Ms. Alexander testified, “the fact that Columbia recognized its poor performance and took steps to improve it is an action that any utility should undertake and is not a basis for rewarding shareholders with a higher profit for meeting standards that are typical of other utilities.”⁶⁸⁴

The OCA recommends that the evidence does not justify any increased profits in Columbia’s rate of return. Any rate increase approved in this proceeding should require that Columbia to maintain its 2024 performance at a minimum during the rate effective year to avoid the potential that increased rates are not accompanied by a lack of attention and commitment in this area once the rate case is concluded. This recommendation is similar to the Company’s own internal performance objective.⁶⁸⁵

ii. Customer Satisfaction Surveys

In support of the performance management adder, Ms. Paloney also presented the Company’s results of Commission’s customer satisfaction surveys that are conducted with the same methodology for all NGDCs. However, as Ms. Alexander noted, Ms. Paloney’s charts do not discuss or present the data that compares Columbia’s results with other NGDCs.⁶⁸⁶ OCA witness Alexander testified:

Columbia’s performance is within the average range of other Pennsylvania natural gas utilities based on the Commission’s approved methodology for conducting and reporting these survey results by all Pennsylvania electric and natural gas distribution companies. [a]ccording to the 2023 Customer Service Performance Report, Columbia’s results for 2021-2023 do not reflect customer satisfaction results in a wide range of measurements of interactions

⁶⁸³ OCA St. 6 at 7.

⁶⁸⁴ OCA St. 6 at 7.

⁶⁸⁵ OCA St. 6 at 12-13.

⁶⁸⁶ OCA St. 6 at 13; Columbia St. 9 at 28-31.

with the call center differ from or is better than other gas utilities. In some areas, the Company's performance is a bit lower or worse than average. For example, Columbia's results for "satisfaction with ease of reaching the company" and "satisfaction with using NGDC's automated phone system" deteriorated from 2021 to 2023. This trend of deterioration in satisfaction is also evident with overall satisfaction, particularly with credit/collection calls from 2021 to 2023.⁶⁸⁷

As with the Call Center performance, Ms. Paloney again attempts to reject the use of the Commission's survey results while relying on the UCARE and Quality of Customer Service Reports to support her recommendation of "superior" performance.⁶⁸⁸ Ms. Paloney instead seeks to rely on results from survey results from its own consultants or to outside entities. OCA witness Alexander testified that "[t]hese other survey results lack transparency in methodology and results compared to the Commission approved survey methodology and results purchased in the PUC annual reports."⁶⁸⁹

Ms. Alexander concluded that these results do not reflect "superior" or "high level" customer service performance, and she found the trend in deterioration from 2021 to 2023 to be "disturbing."⁶⁹⁰ The customer survey results from the PUC reports demonstrate that the Company does not have superior customer satisfaction results.

iii. J.D. Power Customer Satisfaction Survey

Columbia witness Paloney also presented the results of the J.D. Power customer satisfaction survey in support of the "superior" performance claim.⁶⁹¹ OCA witness

⁶⁸⁷ OCA St. 6 at 13 (footnotes omitted).

⁶⁸⁸ Columbia St. 9-R at 7.

⁶⁸⁹ OCA St. 6 at 8.

⁶⁹⁰ OCA St. 6 at 14.

⁶⁹¹ Columbia St. 9 at 30.

Alexander testified that the results are not appropriate to be relied upon because the surveys are conducted with a proprietary methodology and do not allow for a comparison with other Pennsylvania NGDCs that are already available with the Commission's survey results.⁶⁹² In particular, OCA witness Alexander testified that Ms. Paloney's reliance on the J.D. Power survey lacks transparency in methodology and presentation in their data. The survey results also do not include peer results for Pennsylvania utilities since Columbia does not have access to that data.⁶⁹³

3. Conclusion

Columbia's requested 0.25% proposed management performance adder should be denied. Mr. Colton examined the Company's performance regarding low-income customers utilizing the BCS reports to compare to peer natural gas distribution companies in Pennsylvania. In key performance areas including CAP payment rate, the dollars which each utility forgives through their respective CAP each year, termination rates and reconnection rates, and CAP credit in comparison to CAP bills, Columbia's performance has consistently been lower than its natural gas utility counterparts in Pennsylvania. OCA witness Alexander specifically reviewed the Company's call center performance, customer satisfaction surveys, and the Company's claim for success pursuant to a JD Power survey. Ms. Alexander's testimony demonstrated that Columbia witness Paloney's metrics were selective, and that she ignored areas that reflected average or below average or the trend in deterioration in several areas. Mr. Colton and Ms. Alexander both concluded that the

⁶⁹² OCA St. 6 at 14.

⁶⁹³ OCA St. 6 at 8.

Company's initiatives and performance areas do not reflect "superior" performance compared to other NGDCs in Pennsylvania.

X. REVENUE ALLOCATION AND RATE DESIGN

The OCA respectfully requests that the Commission grant significant weight to the Peak & Average (P&A) allocated cost of service (ACOS) study presented by the Company, which is reasonable and is consistent with the Commission's precedent for the allocation of the costs of mains.⁶⁹⁴ The revenue allocation proposal based on the P&A study developed by OCA witness Mierzwa reduces the pre-existing subsidies under present rates indicated by the cost study by moving classes that are overearning towards their indicated cost of service to arrive at the same level of overearning.⁶⁹⁵ Further, the Company's request to increase the residential customer charge from \$17.25 to \$31.97, or by \$14.72 or 85% – despite currently being among the highest customer charges among NGDCs in the Commonwealth – should be rejected as inconsistent with Commission precedent, cost causation, and principles of equity.⁶⁹⁶ Instead of such a significant increase, the OCA recommends that the Commission maintain the Company's current residential customer charge of \$17.25 as it is already the highest residential customer charge in the Commonwealth.⁶⁹⁷ In sum, the OCA's alternative revenue allocation and rate structure should be accepted by the Commission and, to the extent any party's proposal conflicts

⁶⁹⁴ OCA St. 4 at 4-8 (citing *Columbia 2020* at 218).

⁶⁹⁵ OCA St. 4 at 8-12.

⁶⁹⁶ *Id.* at 13-16.

⁶⁹⁷ *Id.* at 16.

with the OCA's, the OCA's should be given greater weight when determining just and reasonable rates.

A. Cost of Service Study

The first step in designing tariffed rates is the selection of an appropriate methodology to determine the costs incurred by a utility to provide service to end-use customers, which informs how the utility's cost of service is allocated between its rate classes and, ultimately, how rates are designed to achieve that cost of service.⁶⁹⁸ Cost of service is a forward-looking exercise which allocates to future beneficiaries their share of the costs incurred to provide them with service.⁶⁹⁹ Where possible, costs of service are directly assigned to the customer class causing the Company to incur that cost.⁷⁰⁰ The remaining costs are grouped by similar function – such as being customer-, demand-, or throughput-related – and allocated based each customer class's contribution to that function.⁷⁰¹

The Company provides service to the following rate classes:

- Residential Sales Service and Residential Distribution Service (RSS/RDS);
- Low-Volume Small General Sales Service, Small Commercial Distribution Service, and Small General Distribution Service (SGSS/DS-1);
- High-Volume Small General Sales Service, Small Commercial Distribution Service, and Small General Distribution Service (SGSS/DS-2);

⁶⁹⁸ See, e.g., *PECO Gas 2020* at 215.

⁶⁹⁹ *Phila. Indus. and Comm. Gas Users Group v. Pa. PUC*, 2025 Pa. Commw. LEXIS 133, * 38 (Pa. Cmwlth. Aug. 1, 2025) (*PICGUG*).

⁷⁰⁰ *Columbia Exh. KLJ-1* at 1.

⁷⁰¹ *Id.* (describing the Company's allocation factors)

- Small Distribution Service and low-volume, Large General Sales Service (SDS/LGSS);
- Large Distribution Service and high-volume, Large General Sales Service (LDS/LGSS);
- Main Line Distribution Service “MLDS); and
- Flexible Rate Provisions and Negotiated Contract Service (Flex).⁷⁰²

One of the most significant costs incurred by a natural gas distribution utility is to install mains which transmit natural gas from the point of interconnection with a transmission pipeline to a customer’s service line.⁷⁰³ There are a number of ways in which mains costs may be allocated as evidenced by the fact that the Company presented three different allocation factors for the costs of mains in this proceeding.⁷⁰⁴ However, the Commission has held the long-standing position that “distribution mains exist and are related to both annual demands and peak demands. Both annual and peak demands must be recognized in the allocation of distribution mains cost if the allocation is to be in accord with the principle of cost-causality.”⁷⁰⁵ The Commission has expressly and consistently rejected the notion that the classification of costs associated with natural gas distribution mains should include any customer component.⁷⁰⁶

The Company’s proposed Peak & Average ACOS more accurately reflects cost causation on Columbia’s distribution system than the Customer-Demand study supported

⁷⁰² OCA St. 4 at 4.

⁷⁰³ Columbia St. 6 at 9.

⁷⁰⁴ OCA St. 4 at 5.

⁷⁰⁵ *See Columbia 2020* at 217; *PGW 2023* at 137.

⁷⁰⁶ *Id.* at 213-18.

by PSU alone.⁷⁰⁷ Instead, the OCA, I&E, and OSBA all support the Company's P&A ACOS study.⁷⁰⁸ Evidence of record does not indicate a sufficient basis to move away from the Commission's precedent supporting the P&A methodology.

1. The results of the Company's P&A ACOS are reasonable and should be given significant weight.

Columbia presented three different ACOS studies in this proceeding. OCA witness Mierzwa described the three different methodologies as follows:

Under the first method, which I will refer to as the Customer-Demand method, distribution mains investment was allocated to each rate class partially based on the number of customers and partially based on the design peak day demands of the customers in each rate class. Under the second method, which I will refer to as the Peak & Average method, the remaining distribution mains investment was allocated 50 percent based on the design peak day demands and 50 percent based on annual, or average daily, demands of the customers in each rate class. In addition to the ACOS Studies prepared using these two methods, the Company prepared an Average ACOS Study which reflects an average of the Customer-Demand and Peak & Average ACOS Studies.⁷⁰⁹

To establish its proposed rates in this proceeding, the Company proposed to use the P&A ACOS study.⁷¹⁰

The Commission should afford substantial weight to the P&A ACOS study relied upon by the Company, OCA, I&E, and OSBA for the basis of their revenue allocation and rate design proposals.⁷¹¹ In the Company's most recent litigated rate case, the Commission

⁷⁰⁷ Compare PSU St. 1 at 19 with PGW 2023 at 137 ("Commission precedent, including the proceeding for the 2007 PGW Rate Case, and the recent proceeding in *Columbia 2020*, weigh against the idea that mains costs include a customer component").

⁷⁰⁸ OCA St. 4 at 8; I&E St. 3 at 38; OSBA St. 1-R at 2.

⁷⁰⁹ OCA St. 4 at 5.

⁷¹⁰ *Id.*

⁷¹¹ Columbia St. 6 at 17; OCA St. 4 at 8; I&E St. 3 at 38; OSBA St. 1-R at 2.

determined that the P&A methodology is the most appropriate for the design and construction of the Company's system and best reflects principles of cost causation.⁷¹² As the Commission stated in that case:

[W]e remain of the opinion that although mains serve customers, it is the throughput that determines the type of main investment because it is the load that determines the main investment, not the number of customers served. The existence of one customer, five customers, or ten customers does not determine the amount of mains investment. Mains investment is driven by the loads placed upon it, not by the number of customers served.

Furthermore, distribution mains exist and are related to both annual demands and peak demands. Both annual and peak demands must be recognized in the allocation of distribution mains cost if the allocation is to be in accord with the principle of cost-causality. It is not reasonable to allocate distribution mains investment based solely on design peak day demands as in Columbia's Customer-Demand ACCOSS. The basic reason Columbia invests in its distribution system is to meet the annual demands for gas by customers. Additionally, a portion of the total cost of distribution service is related to installing a system with enough throughput capacity to meet design peak demands in excess of annual demands.

In this proceeding, the Company presented two customer cost analyses, one that included the cost of mains, and one that excluded the cost of mains. This was done to acknowledge the Commission's preference that no portion of fixed costs or depreciation expense associated with mains should be allocated to the customer cost function. Therefore, the acknowledgement that mains are not customer costs in the sub-set of costs known as the customer cost analysis (presented in CG Exh.111, Sch. 1), supports the idea that the allocation of mains should not be based on the number of customers.

For all these reasons, we find that the Peak & Average allocation methodology is the most appropriate allocation methodology to use in this proceeding because it is based on the premise of load-based investment.⁷¹³

As described by OCA witness Mierzwa, the P&A methodology presented by the Company in this case meets all three of the Commission's criteria: (1) it does not include

⁷¹² *Columbia 2020* at 218.

⁷¹³ *Id.* at 217-18.

a customer component, (2) it recognizes the costs of peak demand, and (3) it recognizes the role that annual throughput plays in distribution system design and buildout.⁷¹⁴ Therefore, the Commission should accept the Company's proposed P&A ACOS study as reasonable for the purposes of allocating revenue among the customer classes and designing rates to recover the Company's established revenue requirement.

2. The Customer-Demand ACOS is unsupported by cost causation principles and Commission precedent and should be given no weight.

As described *supra*, only PSU objects to the use of the P&A ACOS study for the purposes of revenue allocation and rate design, while all other parties which presented testimony on the issue of the appropriate ACOS agreed to the use of the P&A ACOS. Specifically, PSU recommends that the Commission rely on the Company's Customer-Demand study because PSU witness Crist contends that recognizing the role that annual throughput plays in the design and buildout of a natural gas distribution system is not consistent with cost causation principles.⁷¹⁵ PSU's objection is also based, in part, on the amount of costs allocated to rate class LDS/LGSS is greater under the P&A methodology than the Customer-Demand methodology.⁷¹⁶ The arguments raised by PSU should be given little weight because they are inconsistent with Commission precedent, which has identified that – at least for Columbia's distribution system – the number of customers is not a factor of cost causation while throughput is.⁷¹⁷

⁷¹⁴ OCA St. 4 at 5.

⁷¹⁵ PSU St. 1 at 17.

⁷¹⁶ *Id.* at 17, 19.

⁷¹⁷ *Columbia 2020* at 217-18.

In *Columbia 2020*, the Commission stated:

[W]e remain of the opinion that although mains serve customers, it is the throughput that determines the type of main investment because it is the load that determines the main investment, not the number of customers served. The existence of one customer, five customers, or ten customers does not determine the amount of mains investment. Mains investment is driven by the loads placed upon it, not by the number of customers served.⁷¹⁸

Similarly, in *PGW 2023*, the Commission affirmed its decision in *Columbia 2020*, stating that “Commission precedent, including the proceeding for the *2007 PGW Rate Case*, and the recent proceeding in *Columbia 2020*, weigh against the idea that mains costs include a customer component.”⁷¹⁹

The fundamental function of a natural gas distribution system is to provide throughput for customers to receive at their meters which is why it is a reasonable, cost-causative basis for allocating the costs of distribution mains, whereas the distribution system is not designed or constructed merely to connect to customers.⁷²⁰ For example, the Company’s main extension policy driven the connection of additional throughput to the system through a revenues test, instead of justifying the extension of mains merely because of the connection of a customer.⁷²¹

While PSU claims that the reason that the Commission adopted the P&A methodology in *Columbia 2020* was due to errors contained in the Company’s Customer-

⁷¹⁸ *Id.* at 217 (citing *Pa. PUC v. Nat’l Fuel Gas Dist. Corp.*, Docket No. R-00942991, 1994 Pa. PUC LEXIS 134, 83 Pa. P.U.C. 262 (Order Dec. 6, 1994) at 91-92).

⁷¹⁹ *PGW 2023* at 137 (citing *Pa. PUC v. Phila. Gas Works*, Docket No. R-00061931, *et al* (Order entered September 28, 2007) at 80) (citing also *Columbia 2020* at 217).

⁷²⁰ *Columbia 2020* at 215 (adopting the arguments of OCA witness Mierzwa with respect to the deficiencies of the Customer-Demand methodology).

⁷²¹ OCA St. 4R at 8.

Demand ACOS study presented in that proceeding, there is no support for such a conclusion based on the Commission's final order.⁷²² This conclusion is also undermined by the Commission's subsequent adoption of throughput- and demand-based (not customer-based) ACOS methodologies in *PECO Gas 2020* and *PGW 2023*, which would not include a reference to any such errors. Further, as identified by OCA witness Mierzwa, not only has the Commission adopted the P&A methodology in other proceedings, other jurisdictions have similarly adopted the P&A method, demonstrating that the method is not *per se* unreasonable.⁷²³

Finally, Mr. Mierzwa found little support for PSU witness Crist's conclusions that the P&A method overstated the miles of mains attributed to LDS/LGSS customers.⁷²⁴ Namely, Mr. Crist's analysis looked only at costs and not at pipe capacity when assessing the miles of mains delivering natural gas to LDS/LGSS customers even though Columbia does not know the actual mileage of mains used to deliver such gas.⁷²⁵ LDS/LGSS customers use mains upstream of their actual point of delivery, meaning that the 3.4 miles of mains per customer witness Crist suggests should be allocated to LDS/LGSS customers is likely insufficient to delivery natural gas from the point of receipt from an interstate, transmission pipeline to those customers' meters.⁷²⁶ PSU witness Crist's reliance on the difference in unitized rates of return between the SDS/LGSS and LDS/LGSS as

⁷²² *Id.* at 7.

⁷²³ OCA St. 4SR at 9-12

⁷²⁴ OCA St. 4R at 8-9.

⁷²⁵ *Id.* at 9.

⁷²⁶ *Id.* at 10-11.

justification for why the Customer-Demand ACOS study is results-based and does not consider cost causation on the delivery of natural gas by Columbia to end-use customers.⁷²⁷

As a result, no reasonable basis in this proceeding has been presented to warrant deviation from the Commission's well-established precedent that the allocation of mains costs should not include a customer component but should, instead, be based on a combination of annual throughput and peak demand.⁷²⁸ While the appropriate ACOS study methodology is to be determined on a case-by-case basis considering the cost causation principles and design of the NGDC's distribution system, there is no evidence to support the conclusion that the cost causation principles and design of Columbia's distribution system, specifically, warrant the inclusion of a customer-related component for the cost of distribution mains.⁷²⁹ Therefore, the OCA respectfully requests that the Commission grant little weight to the arguments presented by PSU which are results-oriented and not rooted in cost causation principles or the design and build-out of Columbia's distribution system. The Peak & Average methodology more appropriately reflects cost causation for the Company and should be utilized by the Commission for purposes of revenue allocation and rate design.

B. Revenue Allocation

The Commission considers the results of cost of service studies to address ratemaking concerns such as unreasonable inter- and intra-class subsidization through

⁷²⁷ PSU St. 1SR at 10-11.

⁷²⁸ *Columbia 2020* at 217-18; *PGW 2023* at 137.

⁷²⁹ *PECO Gas 2020* at 229.

revenue allocation.⁷³⁰ The Commission may also consider non-cost factors when determining the appropriate cost of service for each class.⁷³¹ Non-cost considerations include rate gradualism and affordability, among others.

After determining the appropriate ACOS methodology, the Commission then determines inter-class rates, “which involves the assignment of the revenue requirement between the various customer classes.”⁷³² Revenue allocation should seek to eliminate class cross-subsidization and move customer classes towards their cost of service.⁷³³ However, the Commission is also charged with balancing public policy considerations such as gradualism, incentivizing conservation, and ensuring that rates are affordable for all customers when allocating revenues between classes.⁷³⁴

As stated by OCA witness Mierzwa, a sound revenue allocation should:

- Utilize class cost-of-service study results as a guide;
- Provide stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to ratepayers or the utility (gradualism);
- Yield the total revenue requirement;
- Provide for simplicity, certainty, convenience of payment, understandability, public acceptability, and feasibility of application; and

⁷³⁰ *Lloyd v. Pa. PUC*, 904 A. 2d 1010, 1020 (Pa. Cmwlth. 2006).

⁷³¹ *Phila. Elec. Co. v. Pa. PUC*, 470 A.2d 654, 658 (Pa. Cmwlth. 1984); *Hoover v. Pa. R.R.*, 27 A. 282, 283 (Pa. 1893) (it is appropriate to consider the conditions and circumstances of service when designing rates).

⁷³² *PECO Gas 2020* at 247.

⁷³³ *Lloyd v. Pa. PUC*, 904 A. 2d 1010, 1020 (Pa. Cmwlth. 2006).

⁷³⁴ *PGW 2023* at 146; *PECO Gas 2020* at 247.

reflect fairness in the apportionment of the total cost of service among the various customer classes.⁷³⁵

Based upon these principles, and relying on the Company's proposed P&A ACOS study, OCA witness Mierzwa proposed a revenue allocation which more accurately reflects customers' cost causation than that recommended by the Company without violating equitable principles.⁷³⁶ To determine which customer classes should receive rate increases and if any customer classes should receive rate decreases, Mr. Mierzwa first determined the relative rate of return for each customer class at present rates and at proposed rates.⁷³⁷ A relative rate of return (RROR) "of less than 1.0 indicates that a customer class is providing revenues that are less than that class's indicated cost of service," while an RROR "of 1.0 indicates that a customer class is providing revenues that are equal to that class's indicated cost of service, and a [RROR] greater than 1.0 indicates that a customer class is providing revenues that are greater than that class's indicated cost of service."⁷³⁸

Based on the Company's revenue allocation, Mr. Mierzwa developed the following table:

⁷³⁵ OCA St. 4 at 9.

⁷³⁶ *Id.* at 11.

⁷³⁷ *Id.* at 8.

⁷³⁸ *Id.*

Columbia Proposed Revenue Distribution⁷³⁹

Class	Present Rates	Proposed Rates	Increase	Percent	Relative Rate of Return	
					Present Rates	Proposed Rates
RSS/RDS	\$472,225,754	\$546,101,990	\$73,876,236	15.6%	1.19	1.18
SGSS/DS-1	58,132,981	68,791,241	10,658,260	18.3%	1.11	1.10
SGSS/DS-2	65,814,353	77,886,598	12,072,245	18.3%	1.12	1.10
SDS/LGSS	43,113,653	50,669,037	7,555,384	17.5%	1.14	1.11
LDS/LGSS	29,678,996	36,012,952	6,333,956	21.3%	0.40	0.47
MLDS	1,890,168	1,890,168	0	0.0%	38.05	28.83
FLEX	3,120,443	3,121,087	644	0.0%	(0.53)	(0.40)
Total	\$673,976,348	\$784,473,073	\$110,496,725	16.4%	1.00	1.00

As can be seen from this table, the Company's proposal makes insignificant movement towards cost of service for the RSS/RDS, SGSS/DS-1, SGSS/DS-2, and SDS/LGSS classes which are currently subsidizing the LDS/LGSS and Flex rate classes. OCA witness Mierzwa found the Company's proposal to be unreasonable for these reasons, and instead recommended the following revenue allocation:

OCA Proposed Revenue Distribution⁷⁴⁰

Class	Present Rates	Proposed Rates	Increase	Percent	Relative Rate of Return		
					Present Rates	Proposed Rates	Change
RES	\$472,225,754	\$537,704,353	\$65,478,599	13.9%	1.19	1.15	\$(8,397,637)
DS-1	\$58,132,981	70,467,256	12,334,275	21.2%	1.11	1.15	1,676,015
DS-2	\$65,814,353	79,904,990	14,090,637	21.4%	1.12	1.14	2,018,392
GSS	\$43,113,653	51,974,631	8,860,978	20.6%	1.14	1.15	1,305,594
LGSS	\$29,678,996	39,410,589	9,731,593	32.8%	0.40	0.57	3,397,637
MLDS	\$1,890,168	1,890,168	(0)	0.0%	38.05	28.83	(0)
FLEX	\$3,120,443	3,121,087	644	0.0%	(0.53)	(0.40)	(0)
Total:	\$673,976,348	\$784,473,073	\$110,496,725	16.4%	1.00	1.00	\$0

⁷³⁹ *Id.* at 9.

⁷⁴⁰ *Id.* at 11.

The primary points of contention regarding revenue allocation are: (1) whether and to what extent the LDS/LGSS should receive a greater rate increase than proposed by the Company and (2) if the LDS/LGSS class receives a greater rate increase, how the increased rates from the LDS/LGSS class should be applied to lower the rate increases for the subsidizing classes. The OCA submits that the LDS/LGSS should receive a rate increase equal to 2.0 times the system average increase, instead of the 1.5 times recommended by the Company.⁷⁴¹ The OSBA adopted a similar position.⁷⁴² Based on the increased amount of revenue allocated to the LDS/LGSS customer class, the OCA recommends that the Commission move the subsidizing customer classes to approximately the same RROR so that each class is subsidizing LDS/LGSS and Flex rate customers the same amount following the rate increase.⁷⁴³ The OCA's recommendations, and the testimony of its expert witness, produce results most consistent with cost causation without violating the equitable principle of gradualism and, therefore, should be given the most weight by the Commission.

- 1. Rate LDS/LGSS are currently underpaying their cost of service and the revenue allocation adopted in this proceeding should move them closer to their cost of service than proposed by Columbia.**

Under present rates, LDS/LGSS and Flex rate customers are currently being subsidized by the other customer classes, with RRORs of 0.40 and (0.53), respectively.⁷⁴⁴

⁷⁴¹ *Id.* at 11.

⁷⁴² OSBA St. 1 at 14.

⁷⁴³ OCA St. 4 at 12.

⁷⁴⁴ OCA St. 4 at 10.

Despite this, under the Company's proposed rate increase, LDS/LGSS would receive a subsidy of \$19,252,450 and Flex rate customers would receive a subsidy of \$42,650,000 for a total of \$61,902,450 in inter-class cross-subsidization borne by chiefly residential and small business customers.⁷⁴⁵ Because Flex rate customers receive service at contract rates, any revenue allocated to the Flex rate customer class except through customer charge increases cannot be reasonably recovered by the Company and, therefore, no party recommended increasing the allocation of a revenue increase to Flex customers.⁷⁴⁶ However, the parties disagreed with how to address the issue of the subsidy currently being provided to LDS/LGSS customers.

The OCA recommended that the revenue allocated to LDS/LGSS customers be increased from 1.5 times the system average increase to 2.0 times the system average increase.⁷⁴⁷ This increase would reduce the subsidy being provided to LDS/LGSS by approximately \$3,397,637 compared to the Company's proposal.⁷⁴⁸ OSBA made a similar proposal.⁷⁴⁹ The Company disagreed with the OCA and OSBA because the Commission in *Columbia 2020* applied a 1.5 times system average increase ceiling for purposes of gradualism, which a 2.0 times increase exceeded.⁷⁵⁰ PSU disagreed with the OCA and

⁷⁴⁵ *Id.*

⁷⁴⁶ *See* Columbia St. 6 at 20.

⁷⁴⁷ OCA St. 4 at 11.

⁷⁴⁸ *Id.* at 10.

⁷⁴⁹ OSBA St. 1 at 13-14.

⁷⁵⁰ Columbia St. 6-R at 10-11.

OSBA because it disagrees with the use of the P&A ACOS study as a basis for performing revenue allocation.⁷⁵¹

Fundamentally, the question is one of gradualism: whether the ceiling applied as an upper limit on a rate increase to ensure that the rate increase does not induce rate shock is appropriately 1.5 times (supported by Columbia) or 2.0 times (supported by the OCA and OSBA). OCA witness Mierzwa stated that “typically an increase of 1.5 to 2.0 times the system average increase is considered consistent with the concept of gradualism.”⁷⁵² While the Commission did apply a gradualism ceiling of 1.5 times in *Columbia 2020*, that is because the Commission adopted the OCA’s proposed revenue allocation which included a 1.5 times increase for the SDS/LGSS and LDS/LGSS customer classes, not because a 2.0 times increase was unsupported by the record.⁷⁵³ The Company’s reliance on this determination is misplaced. Rather, in *PECO Gas 2020*, the Commission approved an increase of 2.5 times the system average increase because “the revenue recognition from that class is still shown to be below its cost to serve and therefore continues to be subsidized by other rate classes.”⁷⁵⁴ Whether 1.5 times or 2.0 times the system average increase is the appropriate ceiling on a rate increase for a particular customer class is a case-by-case determination left to the Commission based on the weight of evidence presented in that proceeding.

⁷⁵¹ PSU St. 1-R at 7.

⁷⁵² OCA St. 4 at 11.

⁷⁵³ *Columbia 2020* at 233.

⁷⁵⁴ *PECO Gas 2020* at 249-50.

In this case, the additional \$3,397,637 allocated to the LDS/LGSS class by OCA witness Mierzwa still produced a subsidy of \$15,854,813 to that customer class and a resultant RROR of 0.57.⁷⁵⁵ Like in *Columbia 2020* and *PECO Gas 2020*, “the revenue recognition from that class is still shown to be below its cost to serve and therefore continues to be subsidized by other rate classes” and is likely to be reasonable.⁷⁵⁶ The OCA’s recommendation is consistent with the principles of cost causation and gradualism as well as Commission precedent.⁷⁵⁷ As a result, the Commission should give greater weight to the OCA’s proposed revenue allocation and give less weight to the proposals which preserve the significant subsidies currently received by the LDS/LGSS customer class, as indicated by the P&A ACOS.

2. The revenue allocation selected by the Commission should move customer classes overpaying their indicated cost of service to the same RROR instead of moving them towards their cost of service by the same amount.

Though the OCA and OSBA agree that the appropriate gradualism ceiling for Rate LDS/LGSS is 2.0 times the system average increase instead of the 1.5 times used by the Company, the OCA and OSBA disagree with how to allocate the difference in revenue among the customer classes currently subsidizing Rate LDS/LGSS. OCA witness Mierzwa provided the following table to summarize the difference between the OCA and OSBA positions:

⁷⁵⁵ OCA St. 4 at 10-11.

⁷⁵⁶ *Columbia 2020* at 233; *PECO Gas 2020* at 249-50.

⁷⁵⁷ OCA St. 4SR at 8.

Comparison of OCA and OSBA Revenue Allocations ⁷⁵⁸ (dollars in millions)						
	OCA		OSBA		Variance	
	Increase	ROR	Increase	ROR	Increase	ROR
RSS/RDS	\$65.48	1.15	\$71.53	1.16	\$6.05	0.01
SGSS/DS-1	\$12.33	1.15	\$9.83	1.08	\$(2.50)	(0.07)
SGSS/DS-2	\$14.09	1.14	\$11.44	1.08	\$(2.65)	(0.06)
SDS/LGSS	\$8.86	1.15	\$7.96	1.13	\$(0.90)	(0.02)
LDS/LGSS	\$9.73	0.57	\$9.73	0.57	\$0.00	0.00
MLDS	\$0.00	28.83	\$0.00	28.83	\$0.00	0.00
FLEX	\$0.01	(0.40)	\$0.01	(0.40)	\$0.00	0.00
Total:	\$110.50	1.00	\$110.50	1.00	\$0.00	1.00

As can be seen from this table, OSBA witness Ewen and OCA witness Mierzwa “proposed the same revenue increases for the LDS/LGSS, MLDS and Flex rate customer classes, but different increases for the RSS/RDS, SGSS/DS-1, SGSS/DS-2, and SDS/LGSS customer classes.”⁷⁵⁹ Under the OCA’s revenue allocation proposal, the subsidy Rates RSS/RDS, SGSS/DS-1, SGSS/DS-2, and SDS/LGSS provide to LDS/LGSS and Flex rate customers are essentially equalized, meaning that they pay the same share of the subsidy as compared to each other.⁷⁶⁰ This recommendation is reasonable and should be given greater weight by the Commission because there is no cost of service basis for RSS/RDS customers to pay a greater share of the subsidy than the other rate classes.

The OSBA’s recommendation is less reasonable because it roughly equalizes the movement towards cost-based rates for the four identified rate classes instead of equalizing the share of the subsidies borne by those classes. The source of the OSBA’s concern is that

⁷⁵⁸ OCA St. 4R at 4.

⁷⁵⁹ *Id.*

⁷⁶⁰ *Id.*

movement towards the same RROR requires SGSS/DS-1, SGSS/DS-2, and SDS/LGSS to receive rate increases greater than the system average rate increase as described in Mr. Mierzwa's proposal.⁷⁶¹ However, due to the pre-existing shortfalls in the LDS/LGGS and Flex rate customer classes, even OSBA witness Ewen's proposal results in rate increases to the SGSS/DS-1, SGSS/DS-2, and SDS/LGSS customer classes greater than the system average increase.⁷⁶² Importantly, as identified above, the residential customer class currently has the highest RROR of 1.19 of the four subsidizing classes at present rates, as compared to the RRORs of the remaining three subsidizing classes ranging between 1.11 and 1.14.⁷⁶³ Under the OSBA's proposal, the residential customer class would still have the highest RROR at 1.16.⁷⁶⁴

Of the classes receiving a rate increase in this case, the residential customer class has the most progress to make towards cost-based rates. Only the OCA's proposed revenue allocation works to reduce the share of the subsidy borne by residential customers. The most equitable result is for the costs of subsidizing the LDS/LGSS and Flex rate customers to be borne evenly between the four unsubsidized customer classes.⁷⁶⁵ The OSBA's proposal would require residential customers to continue to bear the greatest burden in supporting the subsidized customer classes without providing an adequate explanation for doing so. Therefore, the OCA respectfully requests that the Commission grant greater

⁷⁶¹ OSBA St. 1-R at 5.

⁷⁶² OSBA St. 1-SR at 3.

⁷⁶³ OCA St. 4 at 11.

⁷⁶⁴ OCA St. 4R at 4.

⁷⁶⁵ OCA St. 4SR at 7-8.

weight to the OCA’s revenue allocation proposal which moves subsidized customers closer to cost-based rates consistent with the principles of gradualism and more evenly distributes the burden of that subsidy among the unsubsidized customer classes by equalizing the RROR for those classes.

C. Rate Design/Tariff Structure

As stated by the Commission in *PECO Gas 2020*, “[r]ate design requires a careful balance of the competing interests of customer classes as well as prudent application of the principles of cost causation, gradualism, and overall fairness.”⁷⁶⁶ One important component of a rate design is the fixed customer charge which does not vary with customers’ usage. A customer charge should approximate customer-related costs directly attributable to a customer, or those “costs that change directly with its addition or subtraction of a customer.”⁷⁶⁷ However, in considering movement towards cost-of-service for the approximation of direct customer costs in a customer charge, the Commission also considers important policy issues, such as gradualism, the effect on conservation, affordability, and other policy objectives.⁷⁶⁸

The OCA recommends rejecting the residential customer charge increase proposed by the Company. Specifically, Columbia proposes to increase the fixed residential customer charge from \$17.25 per month to \$31.97 per month, an increase of \$14.72 or

⁷⁶⁶ *PECO Gas 2020* at 274.

⁷⁶⁷ OCA St. 4 at 14.

⁷⁶⁸ *Columbia 2020* at 264 (Commission adopts the ALJ’s decision to reject Columbia’s proposed fixed customer charge increase as violating the principle of gradualism, harming low-income customers, and discouraging conservation efforts).

85%. The Company's proposal to increase the residential customer charge is not cost-based, defies gradualism, weakens price signals promoting energy conservation, and exacerbates unaffordability of the Company's rates.⁷⁶⁹ Further, the Company's current customer charge is already the highest of any NGDC in the Commonwealth:

**Comparison of Residential Customer Charges for
Pennsylvania NGDCs⁷⁷⁰**

Columbia Gas of Pennsylvania – Proposed	\$31.97
Columbia Gas of Pennsylvania – Current	\$17.25
Philadelphia Gas Works	\$16.25
Peoples Gas	\$15.75
UGI Gas	\$15.00
Peoples Natural Gas	\$14.50
PECO Energy Company	\$14.25
National Fuel Gas Company	\$14.00

For these reasons, the Company's request to increase its customer charge should be rejected. The arguments raised by the Company about revenue stability do not overcome the Commission's long-standing concerns regarding cost causation, gradualism, affordability, and regulatory consistency and should, as a result, be given little weight. Therefore, the Company's current fixed residential customer charge should be maintained.

⁷⁶⁹ OCA St. 4 at 14.

⁷⁷⁰ *Id.* at 15.

1. Columbia’s residential customer charge is inconsistent with cost causation principles.

As stated by OCA witness Mierzwa, “only those costs that change directly with the addition or subtraction of a customer should be included in the calculation of a customer charge.”⁷⁷¹ The Company’s proposal of \$31.97 also includes costs that do not vary with the addition or subtraction of a single customer, such as mains costs and uncollectible expenses.⁷⁷² Mains costs are not appropriately included in a customer charge because they are not customer-related and do not vary with the addition or subtraction of a single customer.⁷⁷³ Uncollectible expense, similarly, does not vary with the addition or subtraction of a single customer.⁷⁷⁴ Excluding mains and uncollectible costs from the Company’s customer cost analysis reduces the calculated customer charge to \$27.70, which is less than the \$31.97 proposed by Columbia.⁷⁷⁵

Columbia’s support for its calculation of the customer charge is that it “has used this method in support of its customer charges in its previous general rate case filings.”⁷⁷⁶ However, in the last two of the Company’s litigated rate proceedings, the Commission has denied either in whole, or in part, the Company’s request to increase its customer charge.⁷⁷⁷ Merely because the Company has used this analysis in prior cases does not make it reasonable.

⁷⁷¹ OCA St. 4 at 15-16.

⁷⁷² *Id.*

⁷⁷³ *Id.* at 13-14 (citing *Columbia 2020* at 217).

⁷⁷⁴ *Id.* at 16.

⁷⁷⁵ *Id.*

⁷⁷⁶ *Columbia* St. 6 at 14.

⁷⁷⁷ *Columbia 2010* at 51-53; *Columbia 2020* at 264-65.

Instead, the Commission has previously relied upon the direct cost method of determining customer charges based on the cost of service, where only the costs directly associated with the connection or removal of a customer from the system are considered in the customer charge.⁷⁷⁸ While the Commission has recognized that indirect customer costs, “such as employee benefits, local taxes and other general and administrative costs . . . may be considered for inclusion in the customer charge, [] such claims are subject to scrutiny on a case-by-case basis.”⁷⁷⁹ The inclusion of all customer-related costs in a customer charge, even if they are “fixed,” may make the customer charge unreasonable; rather, indirect customer costs are “*includable* in a customer charge cost analysis.”⁷⁸⁰ However, to warrant inclusion of customer-related, indirect customer costs that do not vary with the addition or subtraction of a single customer, the utility must meet its burden of proof that the inclusion of such costs is warranted.⁷⁸¹

Columbia has failed to meet its burden of proof in this instance. First, the \$31.97 residential customer charge proposed by Columbia includes costs which are not even customer-related, because the proposed customer charge includes mains costs which, as stated by OCA witness Mierzwa “are driven by the loads placed upon [the distribution

⁷⁷⁸ See, e.g., *Pa. PUC v. PPL Gas Utilities Corporation*, Docket No. R-00061398, 2007 Pa. PUC LEXIS 2 at *210 (Order entered Feb. 8, 2007) (*PPL Gas 2007*).

⁷⁷⁹ *Pa. PUC v. Aqua Pa., Inc.*, Docket No. R-00038805, 2004 Pa. PUC LEXIS 39 at *98 (Order entered July 23, 2004) (*Aqua 2004*).

⁷⁸⁰ *Pa. PUC v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597 (Order entered Dec. 5 2012) (*PPL Electric 2012*) at 131 (emphasis added) (available at <https://www.puc.pa.gov/pcdocs/1206360.docx>).

⁷⁸¹ 66 Pa. C.S. § 315(a).

system], not the number of customers served.”⁷⁸² While Columbia witness Taylor argues that demand-related costs are “fixed,” do not vary with usage, and should be included in a customer’s fixed monthly charge, Mr. Taylor provides no support for why the Company’s customer charge analysis should ignore both the Company’s P&A ACOS study or Commission precedent which both indicate that mains costs are not customer-related.⁷⁸³

The inclusion of demand-related costs in the proposed residential customer charge are not appropriate for inclusion in a rate mechanism designed to recover a limited number of customer-related costs. Some utilities utilize “demand charges” to recover demand-related costs, which are designed to recover a “portion of a company’s revenue requirement through a measurement of peak demand” based on a customer’s peak usage over a certain period of time.⁷⁸⁴ According to Columbia witness Taylor, a demand charge “is fundamentally different from a fixed monthly charge” like a customer charge or a volumetric charge.⁷⁸⁵ Columbia does not currently charge residential customers – or any customers – a demand charge.⁷⁸⁶ As Mr. Taylor stated, “[i]t’s pretty uncommon across [] North America to have a demand charge for” residential natural gas customers.⁷⁸⁷ Instead, in Pennsylvania, demand-related costs are recovered through volumetric rates, as are throughput-related costs, such as the costs associated with distribution mains.⁷⁸⁸

⁷⁸² OCA St. 4 at 13-14.

⁷⁸³ Columbia St. 17-R at 27.

⁷⁸⁴ Tr. 369-70.

⁷⁸⁵ Tr. 369.

⁷⁸⁶ Columbia St. 6 at 3.

⁷⁸⁷ Tr. 371.

⁷⁸⁸ *PGW 2023* at 163.

Importantly, “fixed” is not a category of cost causation. Whether a cost is “fixed” simply means that the cost is associated with plant that has been placed in service, not the cost basis for why the cost was incurred which is the subject of an ACOS study. The Commission’s rate design decisions should begin with examining forward-looking cost causation, not with a retrospective review of whether plant has been placed in service or not.⁷⁸⁹

Second, and similarly, costs such as uncollectible costs which are not customer-related are not appropriately included in a customer charge. As stated by OCA witness Mierzwa “[u]ncollectible expense does not directly change with the addition or subtraction of a customer and, therefore, should not be included in the calculation of a customer charge.”⁷⁹⁰ The Company responded by arguing that, because customer charges are part of a bill that becomes uncollectible, customer charges should recover uncollectible expenses.⁷⁹¹ However, volumetric rates are also a portion of a customer’s bill which becomes uncollectible; absent an analysis presented by the Company that indicates that uncollectible expense includes only fixed charge revenues, the Company’s logic simply does not bear out.⁷⁹² Columbia has produced no evidence that uncollectible expense varies with the addition or subtraction of a single customer and, therefore, should not be permitted to recover uncollectible expense through customer charges.⁷⁹³

⁷⁸⁹ *Lloyd, supra*.

⁷⁹⁰ OCA St. 4SR at 3.

⁷⁹¹ Columbia St. 6 at 13.

⁷⁹² OCA St. 4SR at 3.

⁷⁹³ *Aqua 2004* at *98.

Third, and finally, the Company's mere presentation of a list of costs it deems to be customer-related is an insufficient basis to support the significant increase proposed in the residential customer charge. As stated by the Commission in *Aqua 2004*, customer-related costs beyond meters and service lines may be considered for inclusion in the customer charge on a case-by-case basis, subject to scrutiny.⁷⁹⁴ The Company's purported analyses do not stand up to scrutiny and should be given little weight due to the failure to identify and explain why the inclusion of such costs is justified.⁷⁹⁵

2. Columbia's residential customer charge is inconsistent with gradualism.

The Commission has previously approved increases which are based in cost of service but are moderated in accordance with the principle of gradualism, where an increase in rates towards full cost of service is phased in over time to prevent customers from rate shock or facing too high of a bill increase all at once.⁷⁹⁶ While the OCA submits that the customer charge for residential which it proposes in this case is based in the cost of service, the residential customer charge proposed by Columbia still violates the principle of gradualism, and any increase towards that charge should be moderated.

The Commission has previously relied upon the "total bill impact" standard to determine whether an increase in a customer charge violates the principle of gradualism.⁷⁹⁷ The total bill impact standard inappropriately re-bundles the costs associated with

⁷⁹⁴ *Id.*

⁷⁹⁵ 66 Pa. C.S. §§ 315(a); 332(a).

⁷⁹⁶ *See, e.g., PGW 2023* at 164.

⁷⁹⁷ *UGI Electric 2017* at 174.

distribution and commodity costs in contravention of the Natural Gas Choice and Competition Act, 66 Pa. C.S. Sections 2201-2212, by examining not just the distribution costs when considering a customer charge increase.⁷⁹⁸ While the OCA does not support the use of the total bill impact standard, due to how increases to fixed customer charges increase unaffordability, the total bill impact of the Company's proposed increase demonstrates that the increase would violate principles of gradualism.

Under the Company's proposal, the residential customer charge would increase by 85%.⁷⁹⁹ This increase is far greater than the 16% increase Columbia proposes for the residential customer class as a whole and is greater than the 14% increase for the residential customer class supported by OCA witness Mierzwa.⁸⁰⁰ Drastically changing the portion of a customer's bill occupied by the residential customer charge affects customers' ability to respond to the proposed rate increase by adjusting their usage or budgeting, especially during the summer months when customers have low to no usage.

Based on the Company's noticed usage amount of 70 therms and noticed bill impact of an increase of \$15.77 from \$138.52 to \$154.29, the portion of residential customers' bills occupied by the customer charge would increase dramatically. Based on a bill of \$138.52, the current customer charge comprises 12% of a current residential customer's

⁷⁹⁸ *Cf. Lloyd*, 904 A. 2d at 1021 ("the 'total bill' impact standard is inconsistent with the changes implemented by the Competition Act. To allow the principle of gradualism to be applied on a total bill basis when each service is a stand-alone rate structure would be like saying that the Commission could apply the principle of gradualism in an electric case based on a customer's total utility bill, i.e., the amount a rate payer would pay for electric, gas, water and telecommunications services.").

⁷⁹⁹ OCA St. 4 at 13.

⁸⁰⁰ *Id.* at 9, 11.

bill.⁸⁰¹ Based on a bill of \$154.29, the Company's proposed customer charge would comprise 21% of a residential customer's bill.⁸⁰² This increase is inconsistent with recent Commission decisions regarding the portion of a customer's bill which the customer charge should occupy.⁸⁰³ Indeed, the Commission rejected Columbia's most recent attempt to increase its customer charge, in part, due to gradualism concerns.⁸⁰⁴

Due to the increase in the portion of a residential customer's bill occupied by the customer charge under the Company's proposal, Columbia's proposed \$31.97 residential customer charge should be rejected and the existing customer charge of \$17.25 should be maintained pursuant to OCA witness Mierzwa's recommendation.

3. Columbia's residential customer charge exacerbates affordability concerns.

Columbia's proposal to increase the customer charge by more than 85% will disproportionately and adversely affect low-income customers.⁸⁰⁵ As stated by OCA witness Colton, "[i]ncreasing the fixed monthly customer charge increases the portion of a bill that a low-income customer cannot avoid by adjusting the customer's usage."⁸⁰⁶ Low-income customers rely on being able to control as much of their bill as possible to be able

⁸⁰¹ $\$17.25 / \$138.52 = 12.45\%$.

⁸⁰² $\$31.97 / \$154.29 = 20.72\%$.

⁸⁰³ *Compare with PGW 2023* at 165 (14.2% of an average customer's annual bill represents the customer charge) *and PECO Gas 2020* at 276 (17.4% of a customer's monthly bill at 8 MCF represents the fixed customer charge).

⁸⁰⁴ *Columbia 2021* at 264 (adopting the Recommend Decision's rejection of a proposed customer charge increase on the basis of gradualism concerns, even after adopting the total bill impact standard)

⁸⁰⁵ OCA St. 5 at 79.

⁸⁰⁶ *Id.* at 81.

to reduce their overall bills through usage reduction efforts. The Commission should be concerned with the methods low-income customers often resort to in order to reduce their consumption, such as reducing their heating temperatures to unsafe or unhealthy levels, using their oven or stove to heat portions of their home, or closing off parts of the home.⁸⁰⁷ High energy burdens not only affect customers' ability to pay their bills, but affect the quality of life for low-income customers.⁸⁰⁸ OCA witness Colton presented the following table regarding low-income customers' energy insecurity:

Household Energy Insecurity, 2020 EIA/DOE Residential Energy Consumption Survey (RECS) ⁸⁰⁹					
2020 annual household income	Any household energy insecurity	Reducing or forgoing food or medicine to pay energy costs	Leaving home at unhealthy temperature	Receiving disconnect or delivery stop notice	Unable to use heating equipment
Less than \$20,000	58.0%	46.9%	24.8%	26.6%	11.2%
\$20,000 to \$39,999	56.1%	46.6%	21.2%	19.5%	9.5%
\$40,000 to \$59,999	46.8%	37.7%	20.7%	18.1%	8.0%
\$60,000 to \$79,999	39.7%	31.3%	15.0%	14.4%	6.3%
\$80,000 to \$99,999	29.3%	21.5%	8.9%	11.5%	4.2%
\$100,000 to \$119,999	20.1%	12.8%	5.7%	7.0%	2.0%
\$120,000 to \$139,999	11.1%	6.1%	4.1%	3.7%	1.2%
\$140,000 or more	7.2%	2.6%	3.1%	1.5%	0.8%

⁸⁰⁷ *Id.*

⁸⁰⁸ *Id.* at 82.

⁸⁰⁹ OCA St. 5 at 82 (citing U.S. Energy Information Admin., Table HC 11.1 Household Energy Insecurity, 2020, available at [chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://www.eia.gov/consumption/residential/data/2020/hc/pdf/HC%2011.1.pdf](https://www.eia.gov/consumption/residential/data/2020/hc/pdf/HC%2011.1.pdf) (accessed April 27, 2023)).

As indicated in this table, “in their efforts to reduce bills to more affordable levels, low-income customers frequently take unsafe and unhealthy actions.”⁸¹⁰ Based on this data, Mr. Colton concluded that:

It is unreasonable for Columbia Gas to make it even more difficult for low-income households to reduce their bills when those households are already forced to resort to heating their homes (or only a portion of their homes) using their kitchen stove or oven. It is unreasonable to make it even more difficult for low-income households to reduce their bills when they are already being forced to keep their homes at unsafe or unhealthy temperatures because they cannot afford to pay their bills.

These households who are forced into engaging in these unsafe and unhealthy activities in their struggle to keep their home energy bills affordable are impeded in their efforts by Columbia’s proposal to increase its fixed monthly customer charge by more than 85%. Columbia’s proposal makes a higher part of the customer’s monthly bill unavoidable through reduced consumption. Those low-income customers taking such actions, in other words, will face a smaller bill reduction as a result of their action should Columbia’s proposed increase in the fixed monthly customer charge be approved, potentially incentivizing more dangerous usage-reduction measures.⁸¹¹

The proposed customer charge increase represents an additional \$177 *each year* that Columbia’s low-income customers already struggling to afford their bills will be forced to pay without the opportunity to avoid the rate increase.⁸¹² In deciding on the appropriate size of a customer charge increase, the Commission must consider the agency afforded to Columbia’s low-income customers: any reduction in low-income customers’ agency to

⁸¹⁰ *Id.* at 83.

⁸¹¹ *Id.*

⁸¹² *Id.* at 87.

control their bills results in increasing concern over the unsafe methods to which such customers may resort to afford to heat their homes.⁸¹³

Columbia relies on the existence of its CAP to alleviate the Commission's concerns regarding the impact of a customer charge increase on low-income customers.⁸¹⁴ However, a very small portion (23%) of Columbia's estimated low-income customer population are enrolled in the Company's CAP, with only 40% of customers enrolled in Columbia's CAP being enrolled in the percentage of income program (PIP) component of CAP, or less than 10% of the Company's overall estimated low-income population.⁸¹⁵ Low-income customers not enrolled in CAP will be the most affected by the Company's customer charge proposal, in part due to the cost of CAP increasing as the Company's customer charge increases.⁸¹⁶

As a result, the Company's proposed customer charge will likely worsen outcomes for Columbia's low-income customers by reducing their ability to control their monthly bills, especially during summer months. Low-income customers in Columbia's service territory generally have high mobility, making it more difficult to realize benefits associated with energy efficiency improvements, and high or extremely shelter burdens, leaving less discretionary funding available to invest in energy efficiency improvements to

⁸¹³ *Pa. PUC v. Roaring Creek Water Co.*, 73 Pa. PUC 373, 400 (1990) (*Roaring Creek 1990*) (affordability "is in both the shareholders' and ratepayers' best interest. Affordable bills will maximize revenues for the Company and will enable ratepayers to continue to receive an essential service.").

⁸¹⁴ Columbia St. 17-R at 32.

⁸¹⁵ OCA St. 5 at 79.

⁸¹⁶ *Id.* at 80.

their home.⁸¹⁷ Similar to the Company's proposal in *Columbia 2020*, the customer charge increase should be rejected due to its disproportionate impact on low-income customers, especially considering that the Company has enrolled a nearly identical proportion of its estimated low-income customers in its CAP.⁸¹⁸

4. Columbia's residential customer charge reduces incentives to pursue energy efficiency and conservation.

By placing a greater portion of a residential customer's monthly bill in the customer charge, which sends no price signal to customers, than in the volumetric portion of a customer's bill, the Company's proposal mutes incentives to conserve energy in contravention of the Commission's long-standing policy.⁸¹⁹ Price signals in rates are intended to shape long-term customer behavior; by having a \$31.97 customer charge, the price signal for rationed access to connection with Columbia's distribution system may outweigh the price signals regarding how customers' usage affects the design and buildout of Columbia's distribution system.⁸²⁰

While Columbia contends that customers may see lower overall annual bills under its proposed customer charge, Columbia presents no evidence regarding how customers interpret the line items on their bills to reflect their understanding of the cost-effectiveness of usage reduction measures.⁸²¹ As described *supra*, the Company's proposed increase to

⁸¹⁷ *Id.* at 89-90.

⁸¹⁸ *Columbia 2020* at 264-65.

⁸¹⁹ OCA St. 4 at 16.

⁸²⁰ *See PECO Gas 2020* at 274 ("Improved price signals can translate into more economically efficient energy usage"); *see also Columbia 2020* at 217 (cost causation for natural gas distribution requires reflection of both peak demand and annual throughput).

⁸²¹ *Columbia St. 17-R* at 33.

the residential customer charge increases the portion of the residential customer's bill attributable to fixed charges as opposed to variable charges. This change interferes with customers' calculus regarding energy efficiency measures. OCA witness Mierzwa identified that "[a]ny increase in the Residential customer charge would reduce the incentive to engage in energy conservation and would limit the benefits residential customers can realize from engaging in energy conservation actions."⁸²²

The Company has presented no evidence to distinguish its proposal in this proceeding from *Columbia 2020*, when a less extreme customer charge increase was rejected, in part, because of the impact of the increase on energy efficiency incentives.⁸²³ As a result, the evidence presented by the Company in this case should be given little weight and its proposal to increase its residential customer charge should be rejected.

5. Overall, Columbia's proposed residential customer charge should be denied and the evidence presented by the OCA, I&E, and CAUSE-PA regarding the residential customer charge should be given greater weight.

The OCA, I&E, and CAUSE-PA all agree that the Company should maintain its current customer charge.⁸²⁴ The Company's proposal to increase its residential customer charge is inconsistent with cost causation, violates the principles of gradualism, would have an adverse impact on low-income customers, and reduces incentives for customers to conserve energy or engage in energy efficiency measures. Further, Columbia already charges the highest residential customer charge in the Commonwealth and would nearly

⁸²² OCA St. 4SR at 5-6.

⁸²³ *Columbia 2020* at 264-65.

⁸²⁴ OCA St. 4 at 16; I&E St. 3 at 43; CAUSE-PA St. 2 at 41-42.

double the next-highest residential customer charge if its proposal to increase its customer charge to \$31.97 were approved.⁸²⁵ If the Commission were to approve Columbia's proposal, then Columbia's residential customer charge would be unreasonably out-of-step with the other residential customer charges in the tariffed rates of Pennsylvania NGDCs.

The Company's primary concern with raising the residential customer charge is its position that fixed costs should be recovered through fixed charges.⁸²⁶ However, the Company's perspective is backwards. The Commission has historically used rate design to shape future customer behavior, as evidenced by its consideration of price signals translating into economically efficient energy usage.⁸²⁷ The Company's pursuit of revenue stability through an increased residential customer charge provides no corresponding benefit to consumers.⁸²⁸ Residential customers comprise approximately 70% of the Company's present rate revenues; increasing the customer charge provides significantly higher assurances of the Company's revenues at the expense of residential customers to the tune of \$177 per year in additional unavoidable costs.⁸²⁹

Columbia's request is unsupported by applicable Commission precedent or fundamental principles of cost causation and equity. Rather, the attempt to have near-guaranteed extraction of additional revenues without exposure to volumetric risks provides

⁸²⁵ OCA St. 4 at 15.

⁸²⁶ Columbia St. 17-R at 30.

⁸²⁷ *See, e.g., PGW 2023* at 163.

⁸²⁸ *See Columbia 2010* at 51 (stable revenues can correspond to a lower cost of capital, "including lower debt costs, and lower expected return on equity by shareholders for stable revenue industries").

⁸²⁹ OCA St. 4 at 9.

the Company immense benefit at customers' expense. Due to this inequity, the OCA respectfully requests that the Commission afford significant weight to the recommendations of OCA witnesses Mierzwa and Colton and maintain the Company's current customer charge of \$17.25.

D. Summary and Alternatives

The OCA's supported cost-of-service study, revenue allocation, and residential customer charge recommendations are supported by the evidence of record and Commission precedent. OCA witness Mierzwa supports the P&A ACOS study presented by Columbia, which is favored by the Commission. As compared to the proposals of the Company, the OSBA, and PSU, the OCA's proposed revenue allocation more closely aligns with equitable principles and cost causation. The Company's proposed deviations from Commission policy and precedent are, inversely, not supported by evidence of record and should be afforded little weight. The OCA respectfully requests that the Commission adopt its recommendations regarding the selection of an appropriate cost of service study methodology, allocation of revenue consistent with that cost study, and the determination of the applicable residential customer charge.

Should the Commission not adopt the Company's proposed revenue requirement, the OCA recommends that the Commission scale-back any rate increase proportionately according to the recommendation of OCA witness Mierzwa, with the exception of Rate MLDS and Flex rate customers.⁸³⁰

⁸³⁰ OCA St. 4 at 12.

XI. ALTERNATIVE RATEMAKING

A. Weather Normalization Adjustment

1. **Columbia's WNA has operated in the past 10 years to extract additional revenues from its customers without providing commensurate benefits to the customers subjected to the WNA.**

Columbia's request to convert its WNA Pilot into a permanent WNA mechanism should be denied because substantial evidence does not support that the WNA Pilot – historically or theoretically – satisfies the Commission's policy factors regarding alternative ratemaking mechanisms, is necessary for Columbia, provides benefits to customers, or is well-understood by Columbia's customers.⁸³¹

While the Commission *may* authorize the implementation of alternative ratemaking mechanisms, such as decoupling mechanisms like the proposed WNA, the proposing utility must provide substantial evidence that the specific mechanism, *proposed by the utility*,⁸³² would result in just and reasonable rates.⁸³³ Section 1330 does not waive the Public Utility Code's burden of proof requirements, or the Administrative Agency Law's requirement that the decisions of Commonwealth agencies – including the Commission – be supported

⁸³¹ 52 Pa. Code § 69.3302(a); OCA Exh. MWD-1 at 3-4.

⁸³² The OCA emphasizes here that the Commission's determination in this proceeding to approve Columbia's request to implement a permanent mechanism must be supported by the record in this case and not based on the approval of prior WNA mechanisms pursuant to settlement agreements. *Bell Atl.-Pa., Inc. v. Pa. PUC*, 672 A.2d 352, 354 (Pa. Cmwlth. 1995) (administrative agencies are not bound by the rule of *stare decisis*, but are, instead, tasked with rendering consistent opinions that affirm, overrule, or distinguish prior opinions).

⁸³³ 66 Pa. C.S. §§ 315(a), 1330.

by substantial evidence.⁸³⁴ In other words, there is no mandate that the Commission *must* implement a proposed alternative ratemaking mechanism, even if the proposed mechanism is based on a pilot which was previously approved pursuant to a settlement agreement. Instead, the utility must still support its proposed mechanism to satisfy the burden of proof required by the Public Utility Code and Pennsylvania law.⁸³⁵

Pursuant to the Settlement Agreement resolving the Company's 2024 rate increase request, which was approved by the Commission, the Company's WNA Pilot will continue until an order is entered in this proceeding, as the first rate case filed by the Company after December 14, 2024.⁸³⁶ Columbia enjoys no presumption of reasonableness for the WNA Pilot which is currently in effect; rather, the Company bears the burden of proof for the proposed continuation of its WNA on a permanent basis, as the Pilot will be discontinued when an order is entered in this proceeding.⁸³⁷ The Company must demonstrate that the WNA results in just and reasonable rates and is distinguishable from other decoupling mechanisms which the Commission found did not meet its policy objectives.⁸³⁸ The Company has failed to do so.

⁸³⁴ See 2 Pa. C.S. § 704 (providing that the decisions of Commonwealth agencies be supported by substantial evidence to survive review of an appellate court).

⁸³⁵ 66 Pa. C.S. § 315(a).

⁸³⁶ *Pa. PUC v. Columbia Gas of Pa., Inc.*, Docket No. R-2024-3046519 (Joint Petition for Settlement filed Aug. 28, 2024) at ¶ 35 (available at: <https://www.puc.pa.gov/pcdocs/1846633.pdf>).

⁸³⁷ 66 Pa. C.S. § 315(a); *Burleson*, 461 A.2d at 1236; cf. *Zucker v. Pa. PUC*, 401 A.2d 1377, 1379-80 (Pa. Cmwlth. 1979).

⁸³⁸ 66 Pa. C.S. § 1301; 52 Pa. Code § 69.3301-69.3302; *Bell Atl. – Pa.*, 672 A.2d at 354; see *Pa. PUC v. Pa.-American Water Co.*, Docket Nos. R-2023-3043189 *et al* (Order entered July 22, 2024) (*PAWC 2023*) at 307-28 (available at: <https://www.puc.pa.gov/pcdocs/1838564.pdf>); *Pa. PUC v. PECO Energy Company – Gas*

OCA witness Deupree describes the proposed WNA as follows:

The Company's WNA is a ratemaking mechanism that adjusts customer bills during the winter heating season (November through May) based on deviations from what the Company defines as "normal" weather. Specifically, it applies a formula using the ratio of normal heating degree days ("HDDs") to actual HDDs, multiplied by a customer-specific heating usage factor, to generate either a credit or a surcharge on the bill. The WNA is limited to weather-related usage changes and applies to residential customers only.

Weather normalization adjustments are generally used to reduce revenue volatility that results from fluctuations in weather which can lower customer gas usage and thus reduce a utility's recovery of fixed costs through volumetric rates. The intent is to provide more predictable revenues for the utility while smoothing customer bills. However, this goal must be balanced with customer protections to ensure the mechanism does not systematically overcharge customers or remove all utility risk.⁸³⁹

Columbia's WNA Pilot has systematically overcharged customers without providing commensurate benefits to customers, extracting approximately \$74 million in additional revenues for Columbia from customers subject to the WNA in the five most recent heating seasons.⁸⁴⁰ "During this period, the Company *never* issued a refund to consumers under the WNA despite claiming that the mechanism is symmetrical. This pattern reveals that the WNA has functioned as a one-sided charge, imposing consistent financial burdens on ratepayers while failing to deliver measurable bill stability or balance."⁸⁴¹ Columbia witness Taylor concedes that, due to recent weather trends as well

Division, Docket No. R-2024-3046932 (Order entered Dec. 12, 2024) (*PECO Gas 2024*) at 94-101 (available at: <https://www.puc.pa.gov/pcdocs/1859395.pdf>).

⁸³⁹ OCA St. 1 at 50.

⁸⁴⁰ OCA St. 1 at 55; OCA Exh. MWD-11; CAUSE-PA St. 2-SR at 14.

⁸⁴¹ OCA St. 1 at 55 (emphasis in original).

as the way that Columbia defines normal weather, the WNA Pilot has only been operating to increase rates for Columbia customers.⁸⁴² Despite positing that the Company could address the deficiencies in the WNA itself and how “normal weather” is defined, Columbia makes no proposal to work towards developing a more effective WNA mechanism; instead, the Company merely seeks to continue the WNA Pilot indefinitely without correcting or addressing the issues that result in one-sided adjustments.⁸⁴³

As stated by OCA witness Deupree:

Despite operating the WNA on a pilot basis for over a decade, the Company has not identified clear criteria for evaluating its performance or demonstrated that the mechanism has produced balanced outcomes for ratepayers. Indeed, the mechanism has functioned as an asymmetric surcharge on customers bills for the past six heating seasons, even though the mechanism was designed to symmetrically provide both surcharges and credits to customers.⁸⁴⁴

In this proceeding, Columbia has not only failed to address the inherent deficiencies in its WNA Pilot which have created lopsided results but proposed to move towards a straight-fixed variable rate design and implement a full decoupling mechanism in order to pull the rug over the flaws in the proposed WNA.⁸⁴⁵ As evidenced by the historic results reported by the Company, as well as compounding pursuits of revenue requirement guarantees, Columbia’s WNA Pilot should be affirmatively discontinued, as it does not result in just and reasonable rates. I&E and CAUSE-PA also submitted testimony that Columbia has failed to meet its burden of proof regarding the proposed WNA for similar reasons as those

⁸⁴² Columbia St. 17 at 39; Tr. 366.

⁸⁴³ *Id.* at 42.

⁸⁴⁴ OCA St. 1 at 58.

⁸⁴⁵ *Id.* at 56.

identified by OCA witnesses Deupree, Colton, and Alexander.⁸⁴⁶ Therefore, for the reasons set forth more fully below, the OCA respectfully requests that the Commission deny Columbia’s request to implement a permanent WNA because Columbia has failed to meet its burden of proof to demonstrate by a preponderance of the evidence that the WNA Pilot has achieved *any* intended benefits for ratepayers and, instead, has only operated to increase rates for Columbia customers.

1. Columbia’s proposed permanent WNA fails to satisfy the Commission’s stated policy factors for approval of alternative ratemaking mechanisms.

To determine “just and reasonable alternative distribution ratemaking mechanisms and rate designs that promote the purpose” of the Commission’s policy and the policy laid out in Section 1330, the Commission developed 14 factors it considers in a policy statement.⁸⁴⁷ This policy statement was enacted following the passage of Section 1330 of the Code, which permits the Commission to use alternative rate mechanisms to further policy objectives, including energy efficiency.⁸⁴⁸ Section 1330 specifically states that “[i]t is the policy of the Commonwealth that utility ratemaking should encourage and sustain investment through appropriate cost-recovery mechanisms to enhance the safety, security, reliability or availability of utility infrastructure and be consistent with the efficient

⁸⁴⁶ See also I&E St. 3 at 5-18; I&E St. 3SR at 8-20; CAUSE-PA St. 2 at 43-63; CAUSE-PA St. 2SR at 11-20.

⁸⁴⁷ 52 Pa. Code § 69.3302(a); see OCA Exh. MWD-1 at 3-4 (evaluating the WNA proposed under the Commission’s 14 policy factors).

⁸⁴⁸ 66 Pa. C.S. § 1330.

consumption of utility service.”⁸⁴⁹ While no one factor is dispositive, the totality of all factors weigh against the authorization and implementation of Columbia’s proposed WNA.

Columbia’s WNA fails to address the Commission’s first policy factor regarding the alignment of revenues with fixed and variable cost causation.⁸⁵⁰ Namely, the WNA adjusts the variable portion of customers’ bills while purporting to recover annual fixed costs of providing gas distribution service.⁸⁵¹ Columbia’s cost of service study does not identify cost-causation as being “fixed” or “variable”; rather, costs are identified as being, *inter alia*, customer-related, demand-related, and throughput-related.⁸⁵² The demand- and throughput-related costs currently recovered through volumetric charges, including the cost of distribution mains, are the costs which are largely recovered through the proposed WNA. Therefore, the proposed WNA operates to adjust customers’ natural gas usage based on weather, creating an inverse relationship between Columbia’s cost of service – as defined by the manner in which distribution rates are designed in Pennsylvania – and how those costs are recovered.⁸⁵³

The proposed WNA also does not impact Columbia’s capacity utilization, as it only adjusts customers’ usage based on weather and not based on utilization, providing no benefit under the Commission’s second policy factor.⁸⁵⁴ Columbia’s argument that the WNA permits more timely recovery of the cost of investments in capacity sufficient to

⁸⁴⁹ 66 Pa. C.S. § 1330(a)(2).

⁸⁵⁰ 52 Pa. Code § 69.3302(a).

⁸⁵¹ OCA Exh. MWD-1 at 3.

⁸⁵² Columbia Exh. KLJ-1.

⁸⁵³ *See PECO Gas 2024* at 96.

⁸⁵⁴ 52 Pa. Code § 69.3302(a); OCA Exh. MWD-1 at 3.

meet peak demands are inapposite, as the second policy factor does not pertain to cost recovery of capacity investment but, instead, refers to the efficiency of a utility's distribution system.⁸⁵⁵ The WNA neither operates to decrease Columbia's ratio of peak demand to average demand nor insulate ratepayers from rate increases due to the inefficient usage of Columbia's distribution system, as the WNA merely adjusts customers' usage to reflect the weather normal Columbia used to estimate consumption in this proceeding.

Under the third policy factor, which considers a mechanism reflecting the level of demand associated with a customer's anticipated consumption, the proposed WNA fails to meet the Commission's criterion.⁸⁵⁶ The proposed WNA adjusts customers' heat-sensitive usage to increase – or, less likely, to decrease – their billed consumption based on differences in weather between the predicted “normal” and the actual weather experience; it is unclear how an adjustment to consumption based on weather could reflect the level of demand associated with anticipated consumption.⁸⁵⁷ Rather, a customer's anticipated consumption is based on their meter readings, actual weather, and recent weather trends, not the “normal” weather for which they are billed under the proposed WNA.

⁸⁵⁵ *Fixed Service Utilities Distribution Rates Policy Statement*, Docket No. M-2015-2518883 (Order entered July 18, 2019) at 13-14 (“As a measure, capacity utilization can be used to judge the efficiency of an electric distribution system. We are interested in consideration of rates by our electric utilities which can work to increase distribution system capacity utilization to foster system efficiency and insulate customers from rate increases.”) (available at: <https://www.puc.pa.gov/pcdocs/1627831.docx>).

⁸⁵⁶ 52 Pa. Code § 69.3302(a).

⁸⁵⁷ OCA Exh. MWD-1 at 3.

The fourth policy factor, which considers inter- and intra-class cost shifting under the mechanism proposed, weighs against implementation of the proposed WNA.⁸⁵⁸ Importantly, Columbia's system is subject to significant interclass cost-shifting under present rates; according to OCA witness Mierzwa, Rate LDS/LGSS and FLEX customers are currently being subsidized by approximately \$68,236,406, particularly by the residential customer class.⁸⁵⁹ Not only does the proposed WNA provide Columbia with a more significant extraction of revenues from the residential customer class, such revenues may be in excess of the actual cost to serve residential customers and include recovery of costs to serve classes currently benefiting from cross-class subsidization. In this way, despite the fact that the proposed WNA is only applicable to the residential customer class, it is a tool which further enables inter-class cross-subsidization due to the pre-existing revenue deficiencies from other customer classes being allocated to the residential customer class.⁸⁶⁰ Furthermore, the proposed WNA can also enable intra-class cost-shifting to the extent that low-income customers have a lesser ability to control their natural gas usage during the heating season than non-low-income customers, resulting in greater WNA

⁸⁵⁸ 52 Pa. Code § 69.3302(a).

⁸⁵⁹ OCA St. 4 at 9-10 (providing that, under present rates, Rate RSS/RDS customers have the second-highest relative rate of return of 1.19 while Rate LDS/LGSS customers have a relative rate of return of 0.40 and Rate FLEX customers have a relative rate of return of -0.53).

⁸⁶⁰ See 66 Pa. C.S. § 1304 ("No public utility shall establish or maintain any unreasonable difference as to rates, either as between localities or as between classes of service."). The OCA notes that the Company submitted no analysis in this proceeding as to why only the residential customer class should be subject to the proposed WNA.

charges and lesser WNA credits for customers with usage patterns inconsistent with that assumed by the proposed WNA.⁸⁶¹

Regarding the fifth and sixth of the Commission's policy factors, which consider the impact of an alternative ratemaking mechanism on incentives and disincentives for pursuing energy efficiency, the Company has failed to demonstrate that the proposed WNA will preserve existing incentives to conserve energy.⁸⁶² In essence, the only way for a customer to avoid a WNA charge during a period of warmer-than-normal weather is to have zero weather-sensitive usage, due to the way that the proposed WNA is calculated. The proposed WNA does not consider reduced usage due to energy efficiency and conservation and, instead, adjusts customers' usage solely due to changes in weather.⁸⁶³ The addition of an unavoidable rate increase which is affected by factors beyond the customer's control will interfere with customers' calculus to determine if reduced consumption or installation of energy efficiency measures will actually be cost-effective. In *PECO Gas 2024*, the Commission determined that the proposed WNA – similar to that proposed by Columbia – interfered with customers' ability to determine the cost-effectiveness of energy efficiency and conservation efforts, despite the ability to reduce bills through a reduced commodity charge.⁸⁶⁴ As a result, customers expecting to save money on their gas bills due to their reduced usage resulting from warmer weather,

⁸⁶¹ OCA Exh. MWD-1 at 3.

⁸⁶² 52 Pa. Code § 69.3302(a); OCA Exh. MWD-1 at 3.

⁸⁶³ OCA Exh. MWD-1 at 3.

⁸⁶⁴ *PECO Gas 2024* at 97.

implemented energy efficiency measures, and/or conservation efforts, will see that their earned bill savings have been recaptured by Columbia through the proposed WNA.⁸⁶⁵

Additionally, Columbia has failed to demonstrate that the proposed WNA should be approved under the Commission's seventh policy factor, which considers the effect of the alternative ratemaking mechanism on low-income customers and CAP.⁸⁶⁶ Company witness Taylor claims that the proposed WNA does not impact low-income customers who are enrolled in CAP under a percentage of income bill plan (PIP).⁸⁶⁷ Importantly, the Commission's policy statement draws a distinction which Columbia does not: low-income customers are distinct from CAP customers. Only approximately 23.3% of Columbia's estimated low-income population is enrolled in the Company's CAP, and not all CAP customers are enrolled in the Percentage of Income Payment (PIP) component of Columbia's CAP.⁸⁶⁸ Tellingly, this discrepancy demonstrates that the Company's reliance on the existence of its PIP component to address the effect that the proposed WNA has on *all* low-income customers is insufficient. Rather, low-income customers are overall less sensitive to changes during the heating season, exhibiting different heating usage behaviors when compared to non-low-income customers, since, as identified by OCA witness Colton,

⁸⁶⁵ See *PAWC 2023* at 307 ("In fact, it appears that the [revenue decoupling mechanism] will hinder customer conservation efforts and could cause customers who take measures to reduce their water consumption to share some of their bill savings with PAWC. We agree that charging customers an additional charge through the RDM may act as a disincentive from conservation practices by customers because it will diminish the value of any savings achieved from such conservation efforts.").

⁸⁶⁶ 52 Pa. Code § 69.3302(a).

⁸⁶⁷ Columbia St. 17 at 31.

⁸⁶⁸ OCA St. 5 at 79.

“they can be expected to turn on their heating units earlier in the season and keep those units running until later in the season.”⁸⁶⁹ This discrepancy is consistent with low-income customers often living in less well-weatherized homes and using less efficient heating systems.⁸⁷⁰ The proposed WNA’s one-size-fits-all approach to adjusting usage fails to capture the difference between how low-income and non-low-income customers react to changes in outside temperatures, resulting in low-income customers overpaying WNA charges during warmer-than-normal winters compared to other customers.⁸⁷¹

Under the eighth of the Commission’s policy factors, considering how the alternative ratemaking mechanism affects rate stability, the Company has failed to provide evidence that the proposed WNA provides rate stability.⁸⁷² This is demonstrated by the frequency of the Company’s rate filings, with the instant proceeding being the eighth rate increase request filed by Columbia since it was permitted to implement its WNA on a pilot basis in 2013 (five rate increase requests since 2019): since the WNA Pilot was first implemented, Columbia has filed a rate case, on average, every year and a half.⁸⁷³ Columbia’s WNA Pilot has not worked to increase stability for customers’ rates because the Company is still consistently seeking near-annual revenue increases, placing a significant upwards pressure on rates over time irrespective of the agency the WNA

⁸⁶⁹ *Id.* at 95.

⁸⁷⁰ *Id.*

⁸⁷¹ *Id.* at 96.

⁸⁷² 52 Pa. Code § 69.3302(a).

⁸⁷³ OCA St. 5 at 7 (providing the Company’s 10 most recent rate increase requests were filed in 2009, 2010, 2012, 2014, 2016, 2019, 2020, 2021, 2022, and 2024).

provides Columbia to extract additional revenues during warmer than normal winters when it would otherwise need to tighten its belt.

Furthermore, the proposed WNA does not provide bill stability. While, in the abstract, the proposed WNA may *theoretically* provide bill stability by providing a more consistent bill for a given month during the heating season, meaning that, for example, bills in February may be adjusted to similar levels of usage each year, theoretical bill stability provides little benefit to Columbia's customers.⁸⁷⁴ Notably, bill stability is difficult to achieve without the rate stability provided by less frequent rate increase requests. OCA witness Colton demonstrated in his testimony, by contrast, that the proposed WNA imposes substantial harms to customers without providing the benefit of more stable natural gas heating bills.⁸⁷⁵ Rather:

The existing Budget Billing program provides a more than satisfactory opportunity to customers who seek to use it. It provides greater benefits to customers without imposing the same risks. Moreover, Budget Billing has the effect of being able to address the volatility in bill payment that arises as a result of variations in cold weather monthly heating bills. The Budget Billing program would play that role in a much more efficient and effective fashion than would the WNA.⁸⁷⁶

Instead of implementing the proposed WNA, Columbia should create greater access to its budget billing program, which provides enrolled customers with actual bill stability, not merely bill stability in the abstract as the Company purports the proposed WNA is intended to provide.

⁸⁷⁴ See Columbia St. 17 at 32.

⁸⁷⁵ OCA St. 5 at 99.

⁸⁷⁶ *Id.* at 99-100.

The ninth policy factor considers how weather impacts utility revenue under the alternative ratemaking mechanism; under the proposed WNA, Columbia’s revenue sees significant benefits due to increasingly frequent warmer winters.⁸⁷⁷ Since the WNA Pilot was implemented in the 2013-2014 heating season, eight out of the 12 heating seasons which have occurred have been warmer-than-normal overall – meaning they resulted in net WNA charges – with no heating seasons resulting in net credits since before the 2019-2020 heating season.⁸⁷⁸ Despite claiming that the WNA Pilot is a symmetrical mechanism, since the fall of 2019, the WNA Pilot has functioned only as a benefit to Columbia without producing any benefit to its customers.⁸⁷⁹ Even Company witness Taylor admits that this one-sidedness is a function of the flaws inherent in a WNA mechanism, meaning that the proposed WNA is likely to continue charging customers as weather becomes warmer over time.⁸⁸⁰ Due to the proposed WNA’s inadequacies as an alternative ratemaking mechanism, variance in weather serves only as a boon to Columbia to the detriment of its customers.

As stated by Mr. Taylor, “[t]he WNA does not impact the Company’s rate case frequency nor does it effect [sic] regulatory lag,” meaning that, under the Commission’s tenth policy factor, neither customers nor the Commission see any benefit from the proposed WNA, despite resulting in additional annual revenues eight out of the last 12

⁸⁷⁷ 52 Pa. Code § 69.3302(a).

⁸⁷⁸ OCA St. 1 at 55.

⁸⁷⁹ *Id.*

⁸⁸⁰ Columbia St. 17 at 40-41.

heating seasons.⁸⁸¹ The proposed WNA's increased revenue stream mutes the ratepayer benefits of regulatory lag, by providing greater incentive for Columbia to manage its costs over time, and has not reduced the frequency of the Company's rate filings to provide Columbia customers with greater rate stability, despite the inter-rate case mechanisms available to Columbia to continue increasing revenues without filing for a rate increase request.⁸⁸² As explained by OCA witness Deupree:

Historically the Company has filed multiple rate case [sic] over the last decade, despite possessing the WNA. This is unlikely to change and the WNA does not prevent the Company from seeking additional rate increases driven by future investment needs or higher expenses and associated cost recovery. The WNA does, however, weaken the positive impacts regulatory lag has on promoting cost containment between rate cases. Regulatory lag has long been recognized as a key component of the overall regulatory compact that disciplines utility operational and investment decisions between rate cases. Regulatory lag in particular diminishes incentives for utilities to overcapitalize since the inefficiencies associated with overcapitalization are passed directly to shareholders until reviewed by the Commission in the utility's next rate case.⁸⁸³

Regarding the eleventh policy factor, which considers how the alternative ratemaking mechanism interacts with other surcharges, the OCA and the Company are in agreement that the proposed WNA does not interact with other surcharges. However, under Section 1357(d)(1) of the Public Utility Code, the Distribution System Improvement Charge (DSIC) applies to revenues recovered under the proposed WNA, meaning that

⁸⁸¹ 52 Pa. Code § 69.3302(a); Columbia St. 17 at 32.

⁸⁸² OCA St. 1 at 11-17.

⁸⁸³ OCA Exh. MWD-1 at 4.

customers' WNA charges will be compounded by the additional percentage amount of the DSIC, creating a bump in Columbia's revenues over and above any WNA charges.⁸⁸⁴

Under the Commission's twelfth factor, regarding consumer protections, Columbia's proposed WNA is clearly deficient.⁸⁸⁵ The proposed WNA includes no check or cap on earnings, which means that there is no ceiling on how much revenue the proposed WNA can extract from Columbia's residential customers.⁸⁸⁶ While the Company claims that the proposed WNA does not, or cannot, over-recover revenues, Columbia witness Taylor points to no part of the way the proposed WNA is applied to customer bills to demonstrate why this is true; rather, implied in Mr. Taylor's statement is the underlying assumption of the proposed WNA that all customers behave perfectly, proportionately responding to changes in weather from year to year by adjusting their natural gas usage with efficient heating equipment and well-weatherized homes.⁸⁸⁷ However, natural gas customers do not always exhibit perfect behavior under perfect circumstances, as demonstrated in Mr. Colton's testimony specifically in regard to the usage patterns of low-income customers.⁸⁸⁸ Under the proposed WNA, Columbia exposes customers exhibiting

⁸⁸⁴ 66 Pa. C.S. § 1357(d)(1) ("The distribution system improvement charge shall be expressed as a percentage carried to two decimal places and shall be applied in a manner consistent with section 1358 (relating to customer protections) to each customer under the utility's applicable rates and charges. The charge shall not be applied to amounts billed for public fire protection service by water utilities and the State tax adjustment surcharge.").

⁸⁸⁵ 52 Pa. Code § 69.3302(a).

⁸⁸⁶ OCA Exh. MWD-1 at 4; *see PECO Gas 2024* at 95 ("there is no 'ceiling' for the revenue that PECO can collect through the WNA" it proposed in that proceeding).

⁸⁸⁷ Columbia St. 17 at 33, 37.

⁸⁸⁸ OCA St. 5 at 95; *see also* OCA St. 1SR at 7-8.

imperfect behavior or acting under imperfect conditions to a greater risk of harm from higher bills than if no WNA were in place at all.

Further, the other “consumer protections” described by Columbia are illusory. Company witness Taylor fails to identify how the identified areas actually benefit the customers to whom the proposed WNA applies.⁸⁸⁹ While the proposed WNA only applies to the residential class, this is not a protection for residential customers but, instead, a boon to other customer classes which (1) are subsidized by the residential class as described *supra* and/or (2) are not subject to the WNA due to the underlying assumption that the usage of those customer classes is not heat sensitive.⁸⁹⁰ In addition, the “regulatory oversight” described by Columbia in testimony is beneficial because it permits *post hoc* review of WNA credits and charges but does not serve to actually protect customers from the WNA on an as-billed basis; this can be seen from the 2022 Petition filing made by the Philadelphia Gas Works, due to the collection of \$12.3 million in WNA charges during the month of May 2022, wherein PGW sought to amend its tariff to implement a control cap on its WNA and remove the month of May from WNA calculations.⁸⁹¹ The resolution of the *PGW 2022 WNA Petition* took over 12 months before a final Commission order was entered, was highly procedurally complex, and created prolonged litigation over how best

⁸⁸⁹ Columbia St. 17 at 33.

⁸⁹⁰ *Id.*; see 66 Pa. C.S. § 1304 (“No public utility shall establish or maintain any unreasonable difference as to rates, either as between localities or as between classes of service”). Columbia did not present evidence regarding whether the proposed WNA should only apply to residential customers.

⁸⁹¹ *Pa. PUC v. Phila. Gas Works*, Docket No. P-2022-3034264 (Order entered Sep. 21, 2023) (*PGW 2022 WNA Petition*) (available at: <https://www.puc.pa.gov/pcdocs/1799650.pdf>).

to address PGW’s significant overcollections in May 2022.⁸⁹² Columbia’s proposed WNA would require a similar type of proceeding, if it initiated such a proceeding on behalf of its customers to begin with.

Though essential, the Company’s purported customer protection of providing transparency regarding the proposed WNA, including disclosures and education materials, is not a protection.⁸⁹³ Rather, educating customers regarding their rates is a core utility function, one which Columbia has performed inadequately with respect to the WNA Pilot. As a result, under the Commission’s thirteenth policy factor, regarding consumer understandability, Columbia’s proposed WNA falls short.⁸⁹⁴ Despite WNAs not being “a new concept to the regulated utility industry” and that Columbia has been billing the WNA Pilot for over a decade, the WNA charge remains a difficult-to-understand bill component that customers cannot predict in advance of their monthly bill.⁸⁹⁵ Because the WNA changes every month based on factors beyond customers’ control – the weather – “[c]ustomers have no means of anticipating future WNA charges as it is impossible for customers to forecast WNA charges in advance and likely difficult for customers to calculate even after the fact.”⁸⁹⁶ Furthermore, the Company’s communication materials

⁸⁹² *Id.*

⁸⁹³ Columbia St. 17 at 33.

⁸⁹⁴ 52 Pa. Code § 69.3302(a).

⁸⁹⁵ Compare Columbia St. 17 at 33-34 with Tr. 367-368 (describing how customers may need to call the Company to determine the inputs to their WNA calculation) and *PECO Gas 2024* at 98-100 (“the WNA is complex and confusing to customers. Indeed, a customer cannot easily look at the multi-variable formula used to calculate the WNA and determine how their bill would be affected by their usage. Moreover, the customer will not have access to all of the data used to complete the bill calculation.”).

⁸⁹⁶ OCA Exh. MWD-1 at 4.

regarding the WNA Pilot are inadequate because they represent the WNA Pilot as working to the benefit of both customers and the Company, which has not historically been the case, and do not provide customers with an individualized calculation of that customer's WNA charge or credit.⁸⁹⁷

Finally, Columbia has not demonstrated that the WNA Pilot has improved its system reliability or overall quality of service, meaning that no benefit is shown under the Commission's fourteenth policy factor.⁸⁹⁸ Despite having a greater amount of revenue extracted from its customers each year due to the WNA Pilot, Columbia has provided no evidence that this revenue supported improvements in its reliability.⁸⁹⁹ The WNA Pilot is not tied to achieving particularly reliability or quality of service improvement goals and has not reduced the Company's frequency of rate case filings, meaning that Columbia's investment in reliability improvements is subject to minimal regulatory lag and can easily be recovered in the next rate case through increased base rate revenues without the need for the additional revenues provided by the WNA.⁹⁰⁰ The proposed WNA merely reduces the benefits associated with regulatory lag for customers, such as a reduced incentive to overcapitalize and stronger incentive to control costs while having no effect on reliability improvements.⁹⁰¹

⁸⁹⁷ OCA St. 6 at 23-25.

⁸⁹⁸ 52 Pa. Code § 69.3302(a).

⁸⁹⁹ OCA Exh. MWD-1 at 4.

⁹⁰⁰ *Id.*

⁹⁰¹ *Id.*

Therefore, each of the policy considerations addressed demonstrates that the WNA is more likely to result in ratepayer harm without providing commensurate benefit to ratepayers, the Commission, or the Company's quality of service. The Commission's policy factors clearly establish that the proposed WNA would not result in just and reasonable rates and should be denied.

2. Columbia's proposed WNA is disfavored by Columbia's customers due to their experience under the WNA Pilot.

The Company's customers who testified at the public input hearings in this case do not support the Company's proposal to make permanent the current WNA Pilot. The public input hearing testimony from this proceeding is summarized in detail in OCA Exh. RDC-

3. As astutely put by consumer Witness Story, the WNA:

[P]rotect[s] Columbia's revenue stream due to decreased consumption, effectively shifting the risk of weather and usage variability away from the utility and onto the ratepayers. Such measures are inconsistent with equitable rate design and send a problematic signal. Ratepayers will pay more regardless of usage while Columbia's profit margins remain protected.⁹⁰²

One customer expressed confusion over the cost basis for WNA charges. Consumer Witness Schlag testified that:

[I]t is totally unfair to charge people for services, products that they don't receive and did not request. I also am a senior citizen and a widow and on a fixed income, and I keep my thermostat at 68. And I am cold in my house a lot of times. And it doesn't make sense that as I try to be very careful how much I consume, that the gas company is charging me for what I don't consume.⁹⁰³

⁹⁰² Tr. 181.

⁹⁰³ Tr. 233.

To the extent that the Company argues that the WNA Pilot has been adequately explained to customers and it is easy to understand, the Company has not sufficiently informed customers that, from its perspective, the WNA is intended to recover fixed costs which are otherwise not recovered through the volumetric component of customers' bills.⁹⁰⁴ Rather, it is clear that Columbia's customers perfectly understand what the WNA Pilot *actually did*, which is adjust their bills to reflect expected usage during warmer-than-normal weather to increase revenue to the Company, instead of what the Company claims the intention of the WNA Pilot was.

Consumer Witness Evans' experience with the WNA Pilot showed a high level of charges which:

totaled \$234.96 that I paid during the weather normalization period that ran from November 2023 through May 2024... for every month except for one [during the 2024-2025 heating season], I was again charged a weather normalization charge. I received one month of a credit of three dollars and some cents.⁹⁰⁵

Ms. Evans' testimony is supported by the overall impact of the WNA Pilot, which reflected over \$74 million in net charges, benefiting the Company to the detriment of its customers.⁹⁰⁶ This is especially true in recent years, as Mr. Taylor stated at hearings, with the last three heating seasons exceeding half of all revenue collected by the Company.⁹⁰⁷

As Columbia witness Taylor identified in his direct testimony, there is no evidence to support the conclusion that the WNA – if made permanent – would achieve markedly

⁹⁰⁴ Columbia St. 17 at 9-10.

⁹⁰⁵ Tr. 218-19.

⁹⁰⁶ CAUSE-PA St. 2-SR at 14.

⁹⁰⁷ Tr. 366.

different results. The asymmetrical results identified by consumer Witness Ms. Evans are due to the fundamental flaws in how the WNA assesses credits and charges because, as Columbia witness Taylor states, “there is not an equivalent probability that actual weather will have an equivalent probability of either being above or below “normal” given the current industry practice for the way that normal weather is defined.”⁹⁰⁸ Instead, as described by consumer Witness Louderback, in each year “Pennsylvania’s residents will be charged more and more.”⁹⁰⁹

Based on the testimony of Columbia’s customers at the public input hearings, it is clear that the WNA Pilot is highly disfavored among consumers. Testifying customers universally voiced support for the termination of the WNA. The Commission’s determination in this proceeding could address these customers’ concerns by declining to permit Columbia to continue its WNA Pilot as a permanent mechanism.

3. Columbia’s use of the FPFTY and DSIC and its frequent filing demonstrate that it does not need the proposed WNA to earn sufficient revenue.

In requesting an alternative ratemaking mechanism to address the problem of weather volatility, the Company has failed to demonstrate a need for it. Columbia avails itself of the ability to recover future expenses which will be incurred through the end of the FPFTY or recover a return on rate base put into service through the end of the FPFTY.⁹¹⁰

⁹⁰⁸ Columbia St. 17 at 38-39.

⁹⁰⁹ Tr. 188.

⁹¹⁰ See 66 Pa. C.S. § 315(e); *McCloskey v. Pa. PUC*, 225 A. 3d 192, 208 (Pa. Cmwlth. 2020) (providing that rates are set in a general rate increase request to recover expenses incurred through the end of the FPFTY).

The Company can also recover the investment in plant made in accordance with its Long-Term Infrastructure Improvement Plan (LTIIP) between rate cases through a DSIC, though it files rate cases so frequently that it does not often receive the benefits of the DSIC.⁹¹¹ Further, Columbia has a historical filing frequency for general rate increase requests of once every 12 to 18 months, showing that the Company is filing rate requests frequently enough to diminish the likelihood of harm from weather volatility. Weather volatility is a consistent and predictable risk for NGDCs and Columbia has presented no evidence to support the fact that it needs a WNA in order to maintain its own financial integrity.

4. The proposed WNA’s departure from principles of cost causation is unwarranted and unsupported.

The proposed WNA unnecessarily departs from principles of cost-causation. One of the primary considerations included by the General Assembly in Section 1330 of the Public Utility Code with respect to the implementation of alternative ratemaking mechanisms is that such mechanisms “should encourage and sustain investment through appropriate cost-recovery mechanisms to enhance the safety, security, reliability or availability of utility infrastructure and be consistent with the efficient consumption of utility service.”⁹¹² The Commission, similarly, considered the alignment of utility revenue recovery with cost causation when designing its Policy Statement regarding alternative ratemaking mechanisms.⁹¹³

⁹¹¹ See 66 Pa. C.S. §§ 1350-1360.

⁹¹² 52 Pa. Code § 69.3301 (“an alternative rate design methodology should reflect the sound application of cost-of-service principles”); 66 Pa. C.S. § 1330(a) (factors 1, 3, 4, and 14 directly pertain to cost-of-service considerations).

⁹¹³ 52 Pa. Code § 69.3302(a)(1).

However, the proposed WNA departs from principles of cost-causation. Specifically, the proposed WNA is calculated to adjust customers' heat-sensitive usage based on how much warmer or colder than "normal" the actual weather is measured to be.⁹¹⁴ According to the Company, the Company's fixed costs – which are largely recovered through volumetric rates – do not change with the weather or with throughput.⁹¹⁵

Importantly, "fixed" is not a category of cost identified in the Company's cost of service study. Costs are instead identified as being related to a specific component of the design of the Company's distribution system, such as the number of customers, the amount of anticipated demand, or the amount of system's amount of annual throughput, to reflect how the Company's customers cause Columbia to incur costs.⁹¹⁶ The proposed WNA does not reflect the collection of additional revenue associated with a particular cost causing factor; demand and throughput do not vary with weather variations. Rather, the proposed WNA recovers costs associated with a purported "value of service" instead of an actual "cost of service," so it is contrary to the principles of cost causation to adjust customers' usage (i.e., their contribution to the class's throughput) to reflect costs previously incurred to serve peak demand.⁹¹⁷

⁹¹⁴ OCA St. 1 at 50-51.

⁹¹⁵ Columbia St. 17 at 29-30, 35-36.

⁹¹⁶ Company Exh. KLJ-1.

⁹¹⁷ *Phila. Indus. and Comm. Gas Users Group v. Pa. PUC*, 2025 Pa. Commw. LEXIS 133, ** 38-41 (Pa. Cmwlth. 2025) (cost causation "is a 'forward-looking principle'" and it is unclear if the use of a "retrospective benefits principle" can be consistent with the requirement that rates be just and reasonable).

As a result, it makes little sense to fabricate usage under the WNA in order to bill customers for greater system utilization when the greater system utilization that was billed-for is not connected to the costs incurred by Columbia to serve that customer.⁹¹⁸ In *PECO Gas 2024*, the Commission agreed with the OCA and PECO Gas’s customers who testified at public input hearings that the proposed WNA was not cost-based because it “is essentially a charge for a product which customers do not use” and has an inverse relationship to the cost-of-service over the WNA’s horizon of recovery, which is beyond the scope of rates set in a Section 1308(d) proceeding.⁹¹⁹

While Columbia may recover certain fixed costs through variable rates, the fact remains that costs are generally variable in the long-run, consistent with the forward-looking exercise of evaluation a customer class’s cost of service, and that Columbia can adjust how it builds out its distribution system to better account for changes in weather or customer usage over time, instead of relying on a poorly designed alternative ratemaking mechanism. The Commission has consistently supported the recovery of fixed costs through volumetric distribution rates *because* such costs are not fixed in the long-term.⁹²⁰ In the *Columbia 2010* proceeding, as part of its general rate increase request, Columbia proposed a rate design which would shift “virtually all distribution costs to the fixed customer charge component” of residential rates.⁹²¹ The Commission rejected this

⁹¹⁸ OCA Exh. MWD-1 at 3.

⁹¹⁹ *PECO Gas 2024* at 96.

⁹²⁰ *Pa. PUC v. Columbia Gas of Pa., Inc.*, Docket No. R-2010-2215623 (Order entered Oct. 14, 2011) (*Columbia 2010*) at 51-53 (available at: <https://www.puc.pa.gov/pcdocs/1149780.docx/>).

⁹²¹ *Id.*

proposal, stating “[s]uch a proposal would have achieved Columbia’s goals of stable revenues, but at the expense of consumer interests in benefiting from energy efficiency investments.”⁹²² The Commission has consistently provided that volumetric distribution rates are the proper mechanism to recover the cost of service which does not vary with the addition or subtraction of a single customer, even if the utility claims that such costs are fixed.

In addition, the only costs which can properly be considered “fixed” are the Company’s claimed costs which extend through the end of the FPFTY, as those are the only costs for which the Company can request recovery in this proceeding. Columbia’s investment in distribution plant, operations and management expenses, and other costs increase may fluctuate as such costs are incurred beyond the FPFTY. The alternative ratemaking mechanisms of the FPFTY and the DSIC already serve to recover not-yet-incurred costs beyond the scope of this proceeding; in other words, Columbia already has the tools to recover costs that will likely *become* fixed between rate proceedings. Planned improvements eligible to be included in an NGDC’s LTIIP – or costs which become fixed but are not fixed at the time of its general rate increase request – are already recoverable through the DSIC until the NGDC adds the improvements to rate base in a subsequent rate proceeding.⁹²³ The Company has presented no evidence to demonstrate that the pre-existing alternative ratemaking mechanisms beyond the WNA Pilot are in some way inadequate to ensure that it will retain the opportunity to earn its revenue requirement.

⁹²² *Id.*

⁹²³ 66 Pa. C.S. § 1357(a).

5. The proposed WNA disincentivizes conservation and energy efficiency by customers because the WNA captures customers' bill savings earned through their reduced usage.

When setting rates, the Commission has long recognized two characteristics of traditional ratemaking and rate design: that customers understand what costs of service their bill contributes towards, or “price signals,” and that the customer be incentivized to conserve energy and reduce their commodity consumption.⁹²⁴ However, the proposed WNA both distorts price signals and reduces the efficacy of customers’ conservation efforts.

Accurate price signals reflect how the services ratepayers receive appear on their bills; fixed charges are meant to reflect the cost of connection, while variable charges reflect the cost of commodity consumption and distribution.⁹²⁵ Accurate pricing policies enable consumers to understand the finite nature of the commodity they receive from the utility and incentivize energy efficiency by reducing bills in proportion to reduced usage and change their long-term behavior to better conserve energy.⁹²⁶ However, a WNA provides *no* price signal to customers because WNA charges do not relate to any service provided by the Company and, instead, reflect historical weather patterns and the purported value of the service provided to customers.

⁹²⁴ See, e.g., *Pa. PUC v. PECO Energy Co. – Gas Div.*, Docket No. R-2020-3018929 (Order entered June 17, 2021) (*PECO Gas 2020*) at 275 (available at: <https://www.puc.pa.gov/pcdocs/1708475.docx>).

⁹²⁵ See, e.g., *Pa. PUC v. PPL Elec. Utils. Corp.*, Docket No. R-2012-2290597 (Order Dec. 28, 2012) at 124-31 (placing sufficient revenue requirement in distribution rates to ensure customers receive accurate price signals and have control over their bills) (available at: <https://www.puc.pa.gov/pcdocs/1206360.docx>).

⁹²⁶ OCA St. 4 at 15.

For example, if a customer experiences an atypically warm March, they may anticipate that their bill for that month will be much lower than the prior year's bill, during a colder March, because they used less natural gas for heating purposes. Yet, under the Company's proposal, the customer would see a bill similar to that of years prior, instead of one directly related to the actual weather experienced. The 30 years of weather data which comprise the normal heating degree day (NHDD) calculation dilute the effect of seasonal or annual trends as the number of heating degree days (HDDs) in 2024 will be assigned equal weight to the number of HDDs in 1995 when determining what weather is "normal."

Because the WNA provides inaccurate price signals, customers have a more difficult time determining whether limiting their consumption or improving their home's energy efficiency is worthwhile. As stated above, accurate price signals are an important part of rate design because they properly incentivize customer conservation of utility service.⁹²⁷ The WNA's distortion of price signals makes it more difficult for customers to determine if investment in energy efficiency measures are sufficiently beneficial to outweigh the cost, or to reward customers for reduced consumption.

In *PECO Gas 2024*, the Commission determined that the WNA proposed in that proceeding "is a disincentive to conservation and energy efficiency programs" and that "it will be difficult for consumers to gauge the return on investment for energy efficiency investments when their efforts to conserve energy are not clearly beneficial in reducing

⁹²⁷ See *PECO Gas 2021* at 274 ("Improved price signals can translate into more economically efficient energy usage.").

their costs.”⁹²⁸ Columbia’s WNA Pilot, and the proposed permanent WNA, similarly disincentivize energy efficiency by manipulating the calculus of the Company’s customers with respect to the benefits of conservation or energy efficiency measures.⁹²⁹ Should energy efficiency investments be made, or conservation measures taken, during a period of warmer-than-normal weather, a customer would see a bill that should be decreased – both due to warmer weather and to their efforts – but is artificially inflated by the WNA. Due to the artificial inflation of natural gas distribution bills during periods of warmer than normal weather under the WNA, customers may have a difficult time determining whether or not their investment or conservation was worth it, thereby affecting their ability or desire to reduce their usage further in the future.

While Columbia witness Taylor argued that customers will still be incented to reduce their usage because it “still reduces their overall bill and the portion of their bill that is subject to the WNA mechanism,” the Commission did not accept this argument in *PECO Gas 2024*.⁹³⁰ As the Commission stated in its Order in that case, “[t]he WNA affects the distribution charge on a customer’s bill, while only commodity charges will be based on actual usage, thus muting the effect of consumers’ efforts to conserve energy on their bill.”⁹³¹ Columbia’s argument in this proceeding, identical to that of PECO Gas’s, should be rejected because a mere reduction in a customer’s bill due to usage reduction does not translate one-to-one to the reduced usage on a customer’s bill during a warmer than normal

⁹²⁸ *PECO Gas 2024* at 96.

⁹²⁹ OCA Exh. MWD-1 at 3.

⁹³⁰ Columbia St. 17 at 31:8-9.

⁹³¹ *PECO Gas 2024* at 96.

month. Instead, the WNA dilutes the customer's reduced usage during warmer than normal months by increasing that reduced usage to somewhere between what the usage would have been had the customer not invested in energy efficiency or conserved gas and where the usage level actually was due to the usage reduction efforts.⁹³² The adjustment under the WNA which places the billed usage in this middle ground represents the portion of customers' savings which are sacrificed to Columbia as a result of the WNA.

Therefore, to the extent that customers elect to take conservation measures if the WNA is put in place, a portion of those savings will be sacrificed to the Company under the proposed WNA.⁹³³ The Company should not be rewarded for the conservation efforts of its customers.⁹³⁴ Customers are entitled to see the dollar-for-dollar decrease to their bill which directly corresponds to the lesser usage resulting from their investment in conservation.

6. Columbia's proposed WNA disproportionately harms the Company's low-income customers.

Columbia's low-income customers, with the exception of those enrolled in the Company's PIP, are disproportionately harmed by the WNA Pilot. Instead, Columbia's low-income customers are better served by the Company's support for its budget billing

⁹³² OCA St. 1SR at 6-7 ("a customer that used approximately 40 therms in the month of April 2025 (approximately 10 percent less than the base of 45 therms) would have seen a final monthly bill of \$50.14. This is more than the \$47.00 monthly bill the same customer using 45 therms would have seen in the absence of the WNA").

⁹³³ OCA Exh. MWD-1 at 3.

⁹³⁴ See *PAWC 2023* at 308 (finding that an alternative ratemaking mechanism which causes customers to share their bill savings with the utility disincentivizes conservation practices).

program, as the WNA Pilot has not yielded the benefits to customers which theoretically support the WNA Pilot's implementation.

According to Columbia witness Taylor, the WNA Pilot may provide “lower bill variability during colder than average periods when gas commodity costs may be higher from increased consumption. In addition, customers who are currently enrolled to pay their bills based on a percentage of their household income see little to no impact to their bills under the WNA mechanism.”⁹³⁵ However, OCA witness Colton's review of the WNA Pilot's results found that low-income customers saw significant charges added to their bills due to warmer than normal weather without producing credits, and especially not producing credits of sufficient size to outweigh the impact of the WNA Pilot charges.⁹³⁶ The increase in bills due to WNA Pilot charges significantly outweighs the theoretical prospective benefit of potential credits – which occur infrequently and are of smaller size than the WNA Pilot charges – for customers living paycheck-to-paycheck.

Considering the usage patterns of low-income customers, specifically, demonstrates the potential harm of converting the WNA Pilot into a permanent mechanism. Identified by Mr. Colton as the “Energy Equity Gap,” customers facing the difficult choice of whether to heat their homes, feed their family, or pay their medical expenses – often referred to as “heat, eat, or treat” – low-income customers have a lower elasticity of demand for natural gas heating than non-low-income customers.⁹³⁷ This means that, as natural gas bills

⁹³⁵ Columbia St. 17 at 31.

⁹³⁶ OCA St. 5 at 92.

⁹³⁷ *Id.* at 93-96.

increase, low-income customers are less responsive in terms of adjusting their usage to curb higher bills than non-low-income customers.⁹³⁸ According to Mr. Colton, low-income customers turn their heating units on earlier in the heating season and leave them on later into the heating season in part due to “less well-weatherized homes and less efficient heating systems.”⁹³⁹ Further, “when winters are warmer than normal, low-income customers will not correspondingly adjust their indoor heating systems and will thus receive” greater WNA charges than non-low-income customers.⁹⁴⁰ In this way, low-income customers are harder hit by WNA charges than non-low-income customers, due to “the underlying assumption of the WNA that all customers react similarly to changes in outdoor temperature.”⁹⁴¹

Instead, the existing budget billing plan is a superior alternative to the WNA for low-income customers to better reduce bill volatility. As described by OCA witness Colton, “[b]udget billing allows a customer to spread annual bills in equal installments over an 11-month period (with Month 12 being a reconciliation month). By enrolling in budget billing, a customer will know from month-to-month what their natural gas bill will be. The bills become more predictable, and thus more payable.”⁹⁴² Though the budget billing programs targets month-to-month bill volatility instead of the year-to-year volatility addressed by the WNA Pilot, low-income customers do not value bill volatility in the

⁹³⁸ *Id.* at 94-95.

⁹³⁹ *Id.* at 95.

⁹⁴⁰ *Id.* at 96.

⁹⁴¹ *Id.*

⁹⁴² *Id.* at 96-97 (citations omitted).

abstract. Customers may struggle to evaluate the year-over-year trends in their bill in a particular billing period (e.g., their bill every January), especially when Columbia requests rate increases every 16 months. As a result, the WNA makes it more difficult for customers to estimate, and, therefore, budget for, their monthly bills during the heating season.

However, the Company limits enrollment in budget billing to customers who have no arrears.⁹⁴³ This limitation means that the “very customers who would most benefit from budget billing, in other words, are those who would be excluded by the Company’s budget billing restrictions.”⁹⁴⁴ According to the data reviewed by Mr. Colton, the Company’s confirmed low-income customers have high seasonal variability in the amount that they owe in arrears, with greater arrearage balances during winter months, even though the number of accounts in arrears has low seasonal variability.⁹⁴⁵ Budget billing, by contrast, would smooth out the seasonal volatility in the amount of arrears because each budget billing plan is calculated so that the customer owes the same amount each month, if customers in arrears were permitted to take advantage of the program.

While Mr. Taylor argues that budget billing and the WNA have different objectives as customers may still pay more in colder-than-normal winters than they would if the WNA were not in effect, his testimony overlooks the consistent one-sided results of the WNA Pilot to date.⁹⁴⁶ For the Company, the WNA does have a different objective than for

⁹⁴³ *Id.* at 97.

⁹⁴⁴ *Id.*

⁹⁴⁵ *Id.* at 98.

⁹⁴⁶ *Compare* Columbia St. 17-R at 10-11 and Columbia St. 17-RJ at 5 with CAUSE-PA St. 2-SR at 14 (“the WNA has surcharged more than \$74.2 million on net since Columbia first implemented its pilot WNA in 2013”).

customers – that being revenue stability – however, the goal of revenue stability should not come at any cost, especially when such costs are disproportionately higher for the Company’s customers least able to afford them. There is, by contrast, little support for the argument that the WNA is also designed to benefit customers by reducing bills during colder-than-normal winters.⁹⁴⁷ As stated by OCA witness Colton:

There can be little question that if the purpose of Columbia Gas is not simply to preserve its revenue stream, but is to help customers improve the predictability and stability of their monthly bills, as was at least initially argued to be the purpose of WNA when it was first presented by witness Kempic and witness Taylor, budget billing is a better mechanism than the WNA to accomplish that purpose.⁹⁴⁸

Based on the history of the WNA Pilot, Mr. Colton concluded that the WNA Pilot does not increase the stability of natural gas heating bills to customers.⁹⁴⁹ Rather, it shifts revenue risk from the Company to its customers in a way which disproportionately affects low-income customers because they have different usage patterns from non-low-income customers. Low-income customers are affected by weather more than other residential customers: they bear a higher burden of heating costs during colder-than-normal and warmer-than-normal heating seasons.⁹⁵⁰ Columbia did not provide evidence to rebut the data which demonstrates this fact.

Furthermore, the existence of the Company’s PIP component of its CAP does not alleviate the burden of the WNA placed on low-income customers. Though the Company

⁹⁴⁷ See Columbia St. 1 at 9; Columbia St. 17 at 28.

⁹⁴⁸ OCA St. 5SR at 21.

⁹⁴⁹ *Id.* at 99.

⁹⁵⁰ OCA St. 5SR at 21-22.

has confirmed the low-income status of 76% of its estimated low-income population, the Company has only enrolled 30% of its confirmed low-income customers in its CAP, or 23% of its total estimated low-income population.⁹⁵¹ Only 9.7% of the Company's low-income customers, or 40% of customers enrolled in CPA, participate in the PIP component of its CAP.⁹⁵² As stated by OCA witness Colton regarding the requested rate increase, generally, "the existence of CAP cannot be used as a reason to ignore the unaffordability of Columbia's proposed rates on the low-income population."⁹⁵³ This applies equally to the proposed WNA. In *PECO Gas 2024*, the Commission held that PECO Gas's under-enrollment of its customers in its CAP meant that the existence of the CAP did not alleviate the impact of the proposed WNA on low-income customers, and found that the proposed WNA disproportionately impacted low-income customers.⁹⁵⁴ The circumstances presented in this proceeding are identical with respect to the impact of the proposed WNA on low-income customers, and the Commission should find in this case, as in *PECO Gas 2024*, that the WNA should be denied, in part, due to the effect on low-income customers.

7. Overall, Columbia has failed to meet its burden of proof that the proposed WNA is a just and reasonable rate.

Despite the significant ratepayer harm caused by the WNA Pilot, Columbia has proposed no improvements or adjustments to its WNA Pilot: the Company simply requests that the Pilot be made into a permanent mechanism.⁹⁵⁵ The Commission should deny this

⁹⁵¹ OCA St. 5 at 25.

⁹⁵² OCA St. 5SR at 24.

⁹⁵³ *Id.*

⁹⁵⁴ *PECO Gas 2024* at 97.

⁹⁵⁵ Columbia St. 17 at 37.

request, for the reasons outlined above, and permit the WNA Pilot to end as agreed-to in the 2024 rate case Settlement.

Importantly, the WNA Pilot has never been subject to a formal evaluation regarding the purpose of the Pilot and what defines success under the Pilot's operations. Columbia is clearly not satisfied with the performance of the WNA Pilot, as the Company has proposed that two additional adjustments to its rate design are necessary: a significant increase in residential customer charges which over-recovers costs associated with the connection or disconnection of a customer and an RNA.⁹⁵⁶ The WNA is a band-aid solution, providing an imprecise and temporary fix to a risk inherent in the natural gas industry – weather – assumed by Columbia when it commenced natural gas service in 1962.⁹⁵⁷ However, “Columbia admits that even with the WNA in place, it continues to experience revenue volatility. This contradiction raises serious concerns about the effectiveness of the WNA and whether it serves any practical purpose beyond creating a one-sided revenue stream for the utility.”⁹⁵⁸ The proposed WNA alone, without providing reduced rates to ratepayers commensurate with the risk shifted to them by the WNA and especially in combination with the proposed significant customer charge increases and RNA, is an example of the type of monopolistic excesses the Commission is charged with protecting against.⁹⁵⁹

⁹⁵⁶ Columbia St. 17 at 42.

⁹⁵⁷ See Columbia St 1 at 3.

⁹⁵⁸ OCA St. 1 at 56.

⁹⁵⁹ *Pittsburgh v. Pa. PUC*, 126 A.2d 777, 784-85 (Pa. Super 1956) (“It is the function of the commission in fixing a fair rate of return to consider not only the interest of the utility but that of the general public as well. The commission stands between the public and the utility and under the law the commission is charged with the duty of protecting the rights of the public.”) (citations omitted).

Other than providing that the proposed WNA is flawed in design, OCA witness Deupree identified that the:

Company has not provided any new study, metric, or performance evaluation to support its request for permanent adoption. The Company has not demonstrated how customers have benefitted from the mechanism, nor has it addressed concerns about the asymmetry and lack of safeguards embedded in the WNA design.⁹⁶⁰

Columbia has not proposed adjustments to its calculations of “normal” weather, which contributes to the WNA’s asymmetry, or demonstrated that the calculations of “normal” weather produces just and reasonable results.⁹⁶¹ As further described by OCA witness

Deupree:

Despite operating the WNA on a pilot basis for over a decade, the Company has never identified criteria or performance metrics by which the WNA would be evaluated. The Company has not defined what would constitute success under the pilot, nor has it conducted any assessment of customer bill stability, fairness, or long-term cost impacts. Without such evaluative benchmarks, the Commission and stakeholders are left with no meaningful way to determine whether the WNA has functioned as intended or delivered any benefits to ratepayers. The Company’s current request to make the WNA permanent underscores the Company’s disregard for the evidentiary and procedural standards typically expected in ratemaking.⁹⁶²

Even though the Company has operated the WNA Pilot for over a decade, the Company has nothing to show for it, except for the extraction of \$74 million from ratepayers. Columbia has presented no evidence that the WNA Pilot has decreased its revenue volatility, improved its ability to invest in reliability and quality of service

⁹⁶⁰ OCA St. 1 at 53 (citations omitted); *compare with* Columbia St. 17 at 37-42 (providing that the design of the WNA has contributed to the asymmetrical nature of the mechanism’s results despite being intended as symmetrical).

⁹⁶¹ OCA St. 1 at 53-54.

⁹⁶² *Id.* at 54 (citations omitted).

improvements, or that its customers are satisfied with the results of the WNA Pilot.⁹⁶³ The Company has not claimed that its cost of capital is reduced due to the WNA Pilot.⁹⁶⁴ Indeed, none of the policy objectives laid out by the Commission for alternative ratemaking mechanisms, or by Section 1330 of the Public Utility Code, have been met by the WNA Pilot.⁹⁶⁵

Instead, Columbia's customers have seen rate increases to the tune of \$74 million, or approximately \$6.7 million per year, extracted by the WNA.⁹⁶⁶ Since the fall of 2019, the WNA has not operated symmetrically, resulting in net charges each heating season.⁹⁶⁷ During the time the WNA has been in effect, the Commission has authorized Columbia to implement seven rate increases, clearly showing that the WNA does not provide relief to Columbia which is otherwise unavailable under Section 1308(d) of the Public Utility Code; rather, the Company's customers are subject to near-annual distribution rate increases in addition to the high monthly bill variance resulting from the WNA.⁹⁶⁸ Columbia's customers do not get the opportunity for rate stability or to benefit from regulatory lag; instead, the Company touts its ability to recover 100% of capital costs with zero lag, reducing its incentives to control costs and increasing its incentives to overcapitalize.⁹⁶⁹

⁹⁶³ OCA St. 1 at 50-56.

⁹⁶⁴ Columbia St. 8 at 38-43.

⁹⁶⁵ See OCA Exh. MWD-1 at 3-4; *see also* 66 Pa. C.S. § 1330(a); 52 Pa. Code §§ 69.3301, 3302.

⁹⁶⁶ OCA Exh. MWD-11; CAUSE-PA St. 2-SR at 14.

⁹⁶⁷ *Id.*

⁹⁶⁸ OCA Exh. MWD-1 at 3-4.

⁹⁶⁹ OCA Exh. MWD-8 at 8.

The OCA submits that Columbia's WNA Pilot is an unequivocal failure. Customers have been harmed without receiving commensurate benefit in the form of reduced rates through adjustments to Columbia's return or less frequent distribution rate increases. The Commission's policy objectives have not benefited as no evidence presented supports the conclusion that the WNA Pilot enabled Columbia to accelerate replacement of priority pipe, improve overall safety and system reliability, or otherwise better invest in its distribution system. The only result of Columbia's WNA experiment is a one-sided revenue extraction mechanism that inequitably shifts a risk knowingly undertaken by the Company and its shareholders in the form revenue volatility associated with weather and foists it upon the Company's customers to their sole detriment. Therefore, the OCA respectfully requests that the Commission deny the Company's request to continue its WNA mechanism as a permanent program and terminate the WNA consistent with Columbia's 2024 rate case settlement, because the Company has not demonstrated by a preponderance of the evidence that the WNA would be a just and reasonable rate if implemented on a permanent basis.

B. Revenue Normalization Adjustment

1. The Company's proposed RNA would not result in just and reasonable rates.

Columbia requests that the Commission approve its proposed Revenue Normalization Adjustment (RNA). OCA witness Deupree described the RNA as follows:

Under the Company's proposal, the RNA would compare actual base rate revenue per customer to the benchmark revenue per customer established in this proceeding. Any differences would be tracked monthly, adjusted for actual customer counts, and reconciled annually through a charge or credit to

customers. Unlike the existing Weather Normalization Adjustment (“WNA”), which only addresses usage variations attributable to deviations from normal weather, the proposed RNA would allow the Company to recover revenue shortfalls regardless of cause. This includes revenue losses due to non-weather factors such as increased energy efficiency, economic conditions, federal appliance standards, or customer conservation efforts.⁹⁷⁰

The RNA is calculated by first determining the benchmark revenue per customer (BRPC). The BRPC is set in a rate case by dividing the authorized revenue requirement for each customer class by the total number of customers in that class.⁹⁷¹ At the end of each year, the Company would calculate the actual revenue per customer (ARPC) by dividing the actual revenue earned for each customer class, including the revenue extracted by the proposed WNA, by the number of customers in that class.⁹⁷² The difference between the benchmark and actual revenue per customer at the end of each year would be charged, if ARPC is less than BRPC, or credited, if ARPC is greater than BRPC, to each customer in the applicable customer class by dividing the difference by 12 and applying that adjustment to each customer’s bill in the applicable class each month beginning the April following the calendar year for which the ARPC was calculated.⁹⁷³ The charge or credit would not vary with the customer’s usage, like under the WNA Pilot. If the RNA does not charge or credit the total amount of the difference between the BRPC and ARPC, then the amount of under- or over-collection is rolled forward to the following calendar year.⁹⁷⁴ Non-CAP

⁹⁷⁰ OCA St. 1 at 17 (citations omitted).

⁹⁷¹ *Id.* at 18.

⁹⁷² *Id.*

⁹⁷³ *Id.*

⁹⁷⁴ *Id.*

residential as well as the commercial and industrial customer classes would be subject to the RNA.

As described *supra* regarding the proposed WNA, the proposed RNA is not necessary for Columbia. The Company has access to sufficient alternative ratemaking tools through the usage of the FPFTY and the potential to use the DSIC to virtually eliminate regulatory lag and have recovery ranging from prospective to contemporaneous for its investments in plant.⁹⁷⁵ This is especially true considering Columbia's near-annual rate increase requests. It is unclear how adding the proposed RNA would enhance the Company's ability to provide adequate, safe, and reliable service to its customers.⁹⁷⁶ The Company presented no argument that its quality of service would improve as a result of the RNA, only that it would be exposed to less throughput-related revenue risk.⁹⁷⁷ Instead, the proposed RNA will almost certainly charge customers for a distribution service they did not use without providing any benefit to customers consistent with a reduced rate of return, improved quality of service, meeting energy efficiency goals, or otherwise providing a tangible benefit.⁹⁷⁸ The proposed RNA operates only to the benefit of Columbia and Columbia's request to implement it should be denied.

Notably, the Commission has not approved a full decoupling mechanism, similar to the RNA, in any prior case. The Commission specifically rejected the revenue decoupling mechanism proposed by Pennsylvania-American Water Company (PAWC) in its 2023 rate

⁹⁷⁵ 66 Pa. C.S. §§ 315(e), 1353.

⁹⁷⁶ OCA Exh. MWD-1 at 1-2.

⁹⁷⁷ Columbia Exh. JDT-2R at 4 (citing 52 Pa. Code § 69.3302(a)(14)).

⁹⁷⁸ OCA St. 1 at 36-37.

case.⁹⁷⁹ The Commission has also rejected Columbia’s prior requests to implement an RNA.⁹⁸⁰ In *Columbia 2020*, the Commission adopted the ALJs’ determination “that Columbia failed to prove the RNA Rider is needed and reasonable, or that the RNA Rider will result in rates that are just, reasonable and in the public interest. Further, the Company did not show its current rates and systems of revenue streams will fail to provide revenue stability.”⁹⁸¹ Columbia presented no evidence in this proceeding sufficient to distinguish its RNA proposed in this case from those specifically rejected by the Commission in *PAWC 2023* and *Columbia 2020* and, for the reasons set forth in those proceedings, the Commission should similarly deny the requested RNA in this case.

There are several clear reasons why Columbia failed to meet its burden of proof that the proposed RNA would result in just and reasonable rates. The OSBA, I&E, CAUSE-PA, and PSU also submitted testimony that Columbia has failed to meet its burden of proof regarding the proposed RNA for similar reasons as those identified by OCA witnesses Deupree, Colton, and/or Alexander.⁹⁸² First, the proposed RNA does not satisfy the Commission’s policy factors regarding alternative ratemaking mechanisms.⁹⁸³ Second, the proposed RNA presents no opportunity for benefit to the Company’s customers. Third, the proposed RNA removes the Company’s incentive to control its costs between rate cases and provides a long-term guarantee of earnings regardless of performance. Fourth, the

⁹⁷⁹ See, generally, *PAWC 2023*.

⁹⁸⁰ *Columbia 2020* at 265.

⁹⁸¹ *Id.* at 264-65 (citing R.D. at 403).

⁹⁸² See OSBA St. 1 at 17-20; I&E St. 3 at 21-28; I&E St. 3SR at 23-31; CAUSE-PA St. 2 at 65-78; CAUSE-PA St. 2SR at 21-22; PSU St. 1 at 20-24.

⁹⁸³ OCA Exh. MWD-1 at 1-2 (citing 52 Pa. Code § 69.3302(a)).

proposed RNA is contrary to the principles of cost causation. Fifth, the proposed RNA will require Columbia's customers to sacrifice potential bill savings from conservation and energy efficiency improvements to the benefit of the Company. For these reasons, the proposed RNA should be denied, as the Company has not demonstrated that the proposed RNA would result in just and reasonable rates.

1. The proposed RNA is deficient under the Commission's policy factors.

As described *supra*, the Commission has developed fourteen policy factors which are assessed to determine whether a proposed alternative ratemaking mechanism would result in just and reasonable rates.⁹⁸⁴ Under the Commission's policy factors, the Company's proposed RNA is deficient and would not result in just and reasonable rates.

The proposed RNA is contrary to the Commission's first policy factor.⁹⁸⁵ Namely, the proposed RNA merely appears as a surcharge on customers' bills and does not reflect the recovery of costs associated with customer-, demand-, or throughput-related cost causation.⁹⁸⁶ Rather, the proposed RNA is not calculated to recover a particular kind of cost; so long as the cost is a distribution cost and not a commodity cost, the RNA will attempt to recover it via a surcharge. This includes costs which vary with the amount of throughput in the Company's cost of service study, such as 50% of mains costs under the Company's proposed cost of service methodology.⁹⁸⁷ Even though the Company may

⁹⁸⁴ *Supra*; 52 Pa. Code §§ 69.3301, 69.3302(a).

⁹⁸⁵ OCA Exh. MWD-1 at 1.

⁹⁸⁶ *Id.*

⁹⁸⁷ Columbia Exh. KLJ-1 at 8 (identifying allocation factor five (mains and mains related accounts) as being the average of the throughput and design day quantities).

consider such costs to be “fixed,” revenue is allocated and customers’ rates are designed based on the forward-looking exercise of cost causation, not on the retrospective consideration of what value has been provided to customers prior to the fixing of rates.⁹⁸⁸

The proposed RNA does not improve customers’ capacity utilization, resulting in no benefit under the Commission’s second policy factor.⁹⁸⁹ As described *supra*, in the Commission’s Policy Statement regarding alternative ratemaking mechanisms, the Commission described “capacity utilization” as aligning a customer’s peak and actual demands.⁹⁹⁰ While the Company claims that the RNA “supports efficient capacity utilization by stabilizing the recovery of fixed distribution costs,” Columbia hides the ball as to explaining how the RNA mechanism supports capacity utilization.⁹⁹¹ Namely, the RNA charges customers for the portion of demand- and throughput-related costs which were not recovered in the prior year; in other words, even though a customer may be more energy efficient by decreasing their annual usage and peak demand, the amount of peak demand that Columbia estimated in its prior rate case will still be recovered. The recovery of peak demand-related costs during periods of non-peak usage does not incentivize efficient utilization of the Company’s distribution system, it merely charges customers the same amount for distribution service regardless of usage.

⁹⁸⁸ *PICGUG* at ** 38-39.

⁹⁸⁹ OCA Exh. MWD-1 at 1; 52 Pa. Code § 69.3302(a)(2).

⁹⁹⁰ *Fixed Service Utilities Distribution Rates Policy Statement* at 13-14

⁹⁹¹ Columbia Exh. JDT-2R at 1.

The proposed RNA also does not reflect demand associated with anticipated consumption levels, thus failing to satisfy the Commission’s third policy factor.⁹⁹² The proposed RNA, as designed, retroactively recovers revenue which the Company did not collect due to its customers’ reduced consumption; any error in the Company’s projections of usage, which are unlikely to be accurate as described *supra* regarding the WNA’s deficiencies, may result in greater RNA charges than anticipated.⁹⁹³ Reductions in consumption associated with installing energy efficiency measures or conservation efforts – or due to large-scale economic pressures such as inflation or a global pandemic – would result in RNA charges the subsequent year.⁹⁹⁴ The proposed RNA in no way reflects actual or anticipated demands, or else demand would be incorporated into the equation; rather, the proposed RNA merely checks whether projected revenues equal actual revenues without consideration as to why those two numbers may be different.

Intra-class cross-subsidization may occur under the proposed RNA, contrary to the Commission’s fourth policy factor.⁹⁹⁵ While the RNA is calculated on a per-class basis, which eliminates the risks of inter-class cross-subsidization, pre-existing cross-subsidization will be furthered under the proposed RNA.⁹⁹⁶ In the example provided by Columbia witness Taylor, it is clear that high usage customers may subsidize low usage customers’ contribution to the amount recovered under the proposed RNA and that the

⁹⁹² OCA Exh. MWD-1 at 1.

⁹⁹³ *Id.*

⁹⁹⁴ OCA St. 1 at 15.

⁹⁹⁵ OCA Exh. MWD-1 at 1.

⁹⁹⁶ *Supra*, OCA St. 4 at 9-10 (Rate LDS/LGSS and FLEX customers are currently being subsidized by approximately \$68,236,406, particularly by the residential customer class).

Company's claim that RNA charges are made on a per-customer basis is unfounded.⁹⁹⁷ The total difference between the BRPC and ARPC are determined by dividing the benchmark and actual revenues from the rate class by the number of customers in that class; there is not an actual calculation of how much revenue the Company projected to earn from each individual customer account based on their demand and usage characteristics. A residential customer who pays \$2,000 annually in Columbia distribution rates would be assessed the same RNA charge each month as a residential customer who pays \$1,000 annually in Columbia distribution rates despite their different contributions to the overall residential class's actual revenue.⁹⁹⁸ In this way, high usage customers would subsidize low usage customers' contribution to overall class revenues as recovered through the proposed RNA.

Under the fifth and sixth of the Commission's policy factors, the proposed RNA would not result in just and reasonable rates because it does not affect disincentives and reduces incentives for pursuing energy efficiency.⁹⁹⁹ At present the Company has not provided evidence that it faces any disincentive to promote energy efficiency with its customers. The Company voluntarily proposed and implemented an Energy Efficiency Pilot Program which ran from 2023 through 2025 and Columbia is proposing to, not only continue the program, but to expand it as part of its rate increase request.¹⁰⁰⁰ The implementation of the energy efficiency program was not contingent on approval of the proposed RNA; rather, the Company's proposed continuation of the program does not seem

⁹⁹⁷ Columbia St. 17 at 47, 49.

⁹⁹⁸ *Id.* at 47.

⁹⁹⁹ OCA Exh. MWD-1 at 1.

¹⁰⁰⁰ Columbia St. 13 at 3, 8.

ties at all to the RNA based on the face of the Company's filing.¹⁰⁰¹ As a result, there is no evidence to indicate that Columbia has a disincentive to expand energy efficiency programs and offerings which would be remediated by implementing the proposed RNA.

Further, under the proposed RNA, customers sacrifice the distribution portion of their bill savings associated with reduced usage due to energy efficiency improvements or conservation. Namely, if the Company does not collect the full BRPC due to customers' conservation efforts in one year, in the following year the difference between the BRPC and ARPC will be spread out over a year, resulting in a surcharge for a prior year's usage reduction efforts.¹⁰⁰² As a result of these bill increases, customers may view their conservation efforts as meaningless because they are ultimately penalized through surcharges for their avoided distribution costs. Under the proposed RNA, any distribution bill savings due to usage reduction are borrowed against next year's bills. The Commission agreed in *PAWC 2023*, stating that the proposed decoupling mechanism "will hinder customer conservation efforts and could cause customers who take measures to reduce their water consumption to share some of their bill savings with" the utility.¹⁰⁰³

The proposed RNA will likely disproportionately affect Columbia's low-income customers, contrary to the Commission's seventh policy factor, though the RNA does not apply to customers enrolled in CAP.¹⁰⁰⁴ As described in detail *supra*, the Company has under-enrolled its low-income population in CAP, with 23.3% of its estimated low-income

¹⁰⁰¹ OCA St. 1 at 34-35.

¹⁰⁰² OCA St. 1SR at 15.

¹⁰⁰³ *PAWC 2023* at 307.

¹⁰⁰⁴ OCA Exh. MWD-1 at 1.

population enrolled in CAP.¹⁰⁰⁵ This means that the RNA will be applied to the vast majority of Columbia's estimated low-income population, even if it does not apply to Columbia's CAP customers. Further, as noted above, the RNA poses significant intra-class cross-subsidization concerns; likely, it is low-income, high usage customers that will foot the bill for higher income, lower usage customers. Low-income households may lack the financial capacity to invest in energy efficiency measures, such as insulation, air sealing, or programmable thermostats.¹⁰⁰⁶ Any reduction in revenue collected from low-income customers already struggling to afford their monthly bill who are currently in arrears or at the risk of falling into arrears is related to a reduction in operating expenses associated with collections activities and uncollectibles expense. The same relationship does not exist for customers who are not similarly payment troubled.¹⁰⁰⁷

Under the Commission's eighth policy factor, regarding rate stability, the proposed RNA would provide no benefit to the Company's customers.¹⁰⁰⁸ Rather, the RNA charges customers for the amount of revenue that the Company did not collect in the prior calendar year; customers have no way to know or predict the amount of revenue under-collection and how that will translate into a surcharge on their bills. Importantly, there is no limit to how high the RNA surcharge can be. Even if calculated correctly and functioning as intended, the RNA could still comprise a significant percentage of customers' bills,

¹⁰⁰⁵ OCA St. 5 at 79.

¹⁰⁰⁶ *Id.*

¹⁰⁰⁷ *Id.* at 106.

¹⁰⁰⁸ OCA Exh. MWD-1 at 2.

especially during summer months where there is no heating usage.¹⁰⁰⁹ The proposed RNA also does not include a proposal to include a deadband, which the Commission has favored for WNAs and would reduce the potential bill volatility resulting from the proposed RNA.¹⁰¹⁰ There is also no evidence to support the conclusion that the proposed RNA, if implemented, would reduce the number of rate cases filed by Columbia, which cause a significant amount of bill volatility for the Company's customers with rates changing every 12 to 18 months.¹⁰¹¹

As stated by the Commission in *PAWC 2023*, the proposed revenue decoupling mechanism (RDM) “would produce guaranteed rate recovery where no guarantee existed in the past and shift the risk of recovery entirely onto customers without any benefit.”¹⁰¹² Due to the utility's “frequency of filing base rate cases, along with its use of the FPFTY and the DSIC, we further find that PAWC has not demonstrated a need for the proposed RDM.”¹⁰¹³ That same reasoning applies here, and Columbia has presented no sufficient basis to distinguish its proposed RNA from PAWC's proposed RDM.¹⁰¹⁴

The proposed RNA extends the proposed WNA by functionally eliminating the deadband, creating greater revenue extraction during periods of warmer than normal

¹⁰⁰⁹ OCA St. 1 at 45.

¹⁰¹⁰ *Id.*; see *Columbia 2020* at 264-65 (upholding the ALJ's determination that the Company's WNA Pilot deadband should not be removed).

¹⁰¹¹ OCA St. 1 at 48-49.

¹⁰¹² *PAWC 2023* at 308.

¹⁰¹³ *Id.*

¹⁰¹⁴ While PAWC utilizes the DSIC to recover the cost of DSIC-eligible plant investment between rate cases and Columbia does not, this is largely due to the frequency of Columbia's rate increase requests, which are more frequent than PAWC's. As a result, Columbia's lack of usage of the DSIC is not a sufficient distinguishing factor.

weather and changing how weather impacts Columbia's revenue under the proposed RNA, which the Commission assesses in its ninth policy factor.¹⁰¹⁵ While the Company states that the RNA addresses different types of revenue fluctuations as compared to the WNA, the fact remains that revenue left uncaptured by the WNA due to the deadband is nevertheless recovered under the RNA.¹⁰¹⁶ As a result, the RNA is still influenced by weather and adjusts the Company's collected revenue based on weather independent of the proposed WNA.

The Company has presented no evidence that the proposed RNA will reduce the frequency of its rate case filings or provides needed relief from regulatory lag and, therefore, the Commission's tenth policy factor weighs against implementation of the proposed RNA.¹⁰¹⁷ Namely, Columbia did not state that it will file rate cases less frequently if the proposed RNA were approved: it will remain on a burdensome 12- to 18-month filing cycle. The Company's failure to commit to reducing the frequency of the constate rate increases inflicted on its customers demonstrates that the proposed RNA is intended to be a one-sided, retroactive extraction of the revenue the Company failed to collect in the year prior and is not intended to benefit the Company's customers.¹⁰¹⁸ Furthermore, the proposed RNA would eliminate the benefits to customers associated with regulatory lag. Regulatory lag disincentivizes overcapitalization while incentivizing cost-savings, creating benefits for customers and opportunities for a utility to increase its efficiency to the benefits

¹⁰¹⁵ OCA Exh. MWD-1 at 2.

¹⁰¹⁶ *Compare* Columbia St. 17 at 50-51 *with* Columbia Exh. JDT-2R at 3.

¹⁰¹⁷ OCA Exh. MWD-1 at 2.

¹⁰¹⁸ OCA St. 1 at 49.

of its shareholders.¹⁰¹⁹ The proposed RNA shifts the risks associated with regulatory lag to Columbia's customers while reducing the Company's disincentives to overcapitalize and incentives to reduce costs, since it is able to recover not only prospective investment through the FPFTY but retroactive revenues it was unable to collect previously.¹⁰²⁰

While the OCA and Columbia agree that the RNA applies only to base rates and does not impact surcharges, the proposed RNA – similar to the WNA – presents the potential for harm under the Commission's eleventh policy factor.¹⁰²¹ Namely, the DSIC applies to revenues recovered under any rate, including alternative ratemaking mechanisms, other than the rates specifically identified in Section 1357(d)(1) of the Public Utility Code.¹⁰²² This means that, if Columbia were to implement the DSIC and customers were subject to a monthly charge under the RNA, then the DSIC would collect additional revenue for Columbia based on the RNA's charges, despite not reflecting investment in DSIC-eligible plant during the period in which the DSIC is in effect.

The proposed RNA also includes no consumer protections, making it clearly deficient under the Commission's twelfth policy factor.¹⁰²³ The Company claims that the proposed RNA has four consumer protections: no over-recovery of revenues, no cross-subsidization, regulatory oversight, and customer transparency.¹⁰²⁴ First, the statement that the RNA does not over-recover revenues directly contradicts the Company's statement that

¹⁰¹⁹ *Id.* at 13-16.

¹⁰²⁰ *Id.* at 46; OCA St. 1SR at 14.

¹⁰²¹ OCA Exh. MWD-1 at 2.

¹⁰²² 66 Pa. C.S. § 1327(d)(1).

¹⁰²³ OCA MWD-1 at 2.

¹⁰²⁴ Columbia St. 17 at 51-52.

the RNA does not guarantee revenue. In a given year the proposed RNA might over-recover revenues but the following year the over-recovered amount will offset any potential RNA charges and potentially be refunded as credits and, by the same reasoning, if the RNA under-recovers in a given year then the following year the under-recovered amount will increase the revenue to be collected under the RNA.¹⁰²⁵ Columbia cannot have it both ways: benefits to the Company and the customer must be viewed over the same time horizon to be compared evenly and, if viewed in perpetuity, the RNA guarantees earnings without over-recovering on revenue whereas, if viewed over the course of a single year, the RNA does not guarantee earnings but can over-recover. Either way, an assurance against over-earning is unlikely to materialize as a protection for customers because customers could still be subject to uncapped, significant bill increases for a calendar year despite the fact that those customers may receive a small credit for over-collections in the following year.

Second, the issue of cross-subsidization is addressed *supra*: while there is some assurance that there will be no inter-class cross-subsidization under the RNA except for the amount authorized by the Commission, there is likely to be intra-class cross-subsidization.¹⁰²⁶ Third, the regulatory oversight provided by the Commission is not tied to the achievement of a particular objective, Rather, it is a mathematical exercise to ensure that the RNA is not being miscalculated; like the WNA Pilot has historically proven, even

¹⁰²⁵ Compare Columbia St. 17 at 51 (“If revenues exceed the benchmark, customers receive refunds or credits, ensuring that Columbia does not collect more than authorized”) with Columbia St. 17-R at 22 (“The RNA is not a guarantee of earnings, it simply aligns actual revenues with revenues already authorized by the Commission”).

¹⁰²⁶ OCA Exh. MWD-1 at 1.

an alternative ratemaking mechanism that is calculated correctly is still able to cause significant ratepayer harm.¹⁰²⁷

Fourth, Columbia's customers' experience with the WNA Pilot demonstrates that the Company's assurance of future customer education is insufficient to warrant being described as a customer protection. OCA witness Alexander's review of the Company's communication and education materials for the WNA Pilot found them to be misleading and inadequate; this is compounded by Columbia's failure to produce documentation regarding how it will present the RNA to customers or how much will be required in rates to educate customers on, and bill them for, the RNA.¹⁰²⁸ Ms. Alexander's discussion also bears on the Commission's thirteenth policy factor, regarding customer's ability to understand the mechanism, where the proposed RNA is also deficient.¹⁰²⁹ In *PAWC 2023*, the Commission rejected a similar full decoupling mechanism to the proposed RNA, in part, because it would "likely be confusing and difficult to understand for consumers due to its complex design in determining whether the RDM is a credit or charge. This additional surcharge on customer bills, along with the quarterly rate changes that occur under PAWC's DSIC, would only add to that complexity and confusion."¹⁰³⁰ Columbia witness Taylor's reliance on the approval of RNAs by other utilities in other jurisdictions is not

¹⁰²⁷ See *Popowsky v. Pa. PUC*, 869 A.2d 1144, 1156 (Pa. Cmwlth. 2005) *alloc. denied* *Popowsky v. Pa. PUC*, 895 A.2d 552 (Pa. 2006) ("the 'cursory' review undertaken for a surcharge is not a substitute for the review undertaken in a base rate case to determine whether a rate is just and reasonable") (citing *Masthope Rapids Property Owners Council v. Pa. PUC*, 581 A.2d 994, 1001 (Pa. Cmwlth. 1990)).

¹⁰²⁸ OCA St. 6 at 23-26; OCA St. 6SR at 1-2.

¹⁰²⁹ OCA Exh. MWD-1 at 2.

¹⁰³⁰ *PAWC 2023* at 308.

evidence of the fact that the RNA is an easy to understand mechanism.¹⁰³¹ Notably, as identified *supra*, no RNA has been approved in Pennsylvania, meaning that customers are likely unfamiliar with the terminology surrounding the RNA.

Columbia's customers would see no benefit to the distribution system's reliability, in contravention of the Commission's fourteenth policy factor.¹⁰³² The proposed RNA does not permit decoupling only in the event that the Company demonstrates that it is making improvements to system reliability, which is the purpose of the DSIC.¹⁰³³ As identified by OCA witness Deupree, other utility commissions in approving decoupling mechanisms have developed reliability standards and targets which had to be met before a utility was authorized to collect revenue normalizing adjustments to customers' bills.¹⁰³⁴ Investments in reliability are generally recovered through base rates due to the Company's use of the FPFTY and there is no evidence to suggest that the RNA is necessary for the Company to accelerate replacement of aging pipe or engage in leak detection when little time passes between the end of the Company's FPFTY in a rate case and the effective date of new rates in its next rate case.

In sum, by reviewing the Commission's 14 policy factor considerations, it is clear that the proposed RNA would not result in just and reasonable rates. Instead, the proposed RNA would operate to increase the Company's revenues without providing a corresponding benefit to consumers. Indeed, the Company posits nowhere in testimony

¹⁰³¹ Columbia Exh. JDT-2R at 4.

¹⁰³² OCA Exh. MWD-1 at 2.

¹⁰³³ OCA St. 1SR at 5.

¹⁰³⁴ OCA St. 1 at 40-41.

that the proposed RNA will benefit customers. Without providing just and reasonable compensation to Columbia's customers for the business risk shifted onto them under the proposed RNA, there is no basis to conclude that the proposed RNA is an appropriate ratemaking mechanism to implement for Columbia.

2. The proposed RNA presents no potential benefit to Columbia's customers and is likely to result in increased rates.

At the outset, the proposed RNA is likely to produce consistent charges and few, if any, credits. As described by OCA witness Deupree, "natural gas utilities as a whole have experienced falling use per customer trends for decades as customers purchase more energy-efficient appliances."¹⁰³⁵ While the Company may claim that the RNA is designed to operate symmetrically, the same was said regarding the WNA Pilot which – for the past five years – has produced immense net charges.¹⁰³⁶ The Company's request for the proposed RNA is unsupported by any analysis of how the proposed RNA would have functioned in historical periods, and "no supporting documentation or workpapers were prepared to justify the benchmark revenue per customer levels proposed under the RNA."¹⁰³⁷ Without an understanding of how the proposed RNA would affect customers, Columbia has failed to meet its burden of proof that the proposed RNA can result in just and reasonable rates.

In the absence of any data supplied by the Company to support its RNA proposal, OCA witness Deupree looked to the experience of other jurisdictions with decoupling. A

¹⁰³⁵ OCA St. 1SR at 15.

¹⁰³⁶ *Compare* Columbia St. 17-R at 22 *with* OCA Exh. MWD-11.

¹⁰³⁷ OCA St. 1 at 31.

survey of 65 natural gas utilities with decoupling shows that, during the period reviewed, 72.3% of reconciliations under the decoupling mechanism generated surcharges, with 18.5% of all reconciliations being surcharges of greater than three percent.¹⁰³⁸ By comparison to surcredits of greater than three percent, during the period reviewed, surcharges of greater than three percent were six times more likely to occur than surcredits of greater than three percent.¹⁰³⁹ The results of a different study reviewed by Mr. Deupree reached the same conclusion, finding that jurisdictions with decoupling experienced more significant rate increases over a period of 12 years in comparison to those without decoupling, with a particularly negative effect on low-income customers, without resulting in the policy aims for which the mechanisms were approved.¹⁰⁴⁰ As a result, not only are decoupling mechanisms more likely to produce charges than credits, they are more likely to produce significant charges than significant credits, with a disproportionate impact on low-income customers, without achieving the stated policy goals.

Columbia's rates are already among the highest for peer natural gas distribution utilities in the mid-Atlantic.¹⁰⁴¹ In terms of average residential sales revenue per MCF, Columbia currently charges the highest rates in Pennsylvania.¹⁰⁴² Increasing these rates further through the implementation of the proposed RNA would increase the gap between

¹⁰³⁸ OCA Exh. MWD-6.

¹⁰³⁹ *Id.*; OCA St. 1 at 37.

¹⁰⁴⁰ OCA St. 1 at 38-39.

¹⁰⁴¹ *Id.* at 39.

¹⁰⁴² OCA Exh. MWD-7 at 2.

Columbia's residential rates and those for other NGDCs in Pennsylvania and should be a source of alarm for the Commission.

In exchange for the strong likelihood of increased bills, Columbia's customers receive no benefit. Columbia strongly contested the idea that any reduction to its return on equity should be authorized if the RNA is implemented associated with its reduced revenue risk.¹⁰⁴³ The Company provided no evidence or analysis to support its contention that the cost of equity for the members of the proxy group relied upon by Columbia witness Rea and OCA witness Garrett was influenced by the implementation of decoupling mechanisms.¹⁰⁴⁴ As other jurisdictions have recognized, it is appropriate to adjust a utility's return on equity due to its reduced revenue risk under decoupling as a way to compensate ratepayers for the risk that they are forced to bear.¹⁰⁴⁵

The risk borne by ratepayers is especially grievous during periods of economic downturn, such as during the recent COVID-19 pandemic. The proposed RNA does not differentiate the type of costs it recovers, meaning that if customers reduce usage – resulting in less billed throughput for the Company – due to harsh economic conditions in order to be able to afford to maintain their service, those customers will be charged their savings in the subsequent year even if conditions have not improved.¹⁰⁴⁶ Decoupling mechanisms effectively shield a utility from lost earnings during periods of economic turmoil to the detriment of their ratepayers, as demonstrated by Central Main Power

¹⁰⁴³ Columbia St. 9 at 17.

¹⁰⁴⁴ OCA St. 1SR at 17.

¹⁰⁴⁵ OCA St. 1 at 40-41; OCA Exh. MWD-10.

¹⁰⁴⁶ OCA St. 1 at 42.

Company's Electric Revenue Adjustment Mechanism, which extracted excessive surcharge revenues in part because an economic recession occurred in the year prior.¹⁰⁴⁷ Other utilities have emphasized the benefits that decoupling provides during periods of economic decline to their shareholders.¹⁰⁴⁸ While demand for natural gas is relatively inelastic for customers who rely on it for heating purposes, customers faced with economic hardship due to a recession or global pandemic use whatever tools they have to endure, including reducing usage. The proposed RNA presents the troubling possibility of exacerbating harms to consumers due to their efforts to endure.

Furthermore, the proposed RNA is not conditional or targeted to improve Columbia's performance. Columbia has not tied its RNA to energy efficiency or demand-side management goals.¹⁰⁴⁹ As described by OCA witness Deupree, "the proposal lacks the kind of integrated framework that other jurisdictions have adopted when approving decoupling mechanisms in conjunction with robust, performance-based energy efficiency commitments."¹⁰⁵⁰ Instead, the Company has proposed to expand its current energy efficiency programs irrespective of the approval of the RNA.¹⁰⁵¹ The Company has not proposed any reliability standards associated with the proposed RNA, which has also been employed in other jurisdictions.¹⁰⁵² In sum, under the proposed RNA, Columbia will continue the *status quo* but extract additional revenues from its customers.

¹⁰⁴⁷ *Id.* at 41-42.

¹⁰⁴⁸ *Id.* at 43-44.

¹⁰⁴⁹ OCA St. 1 at 31.

¹⁰⁵⁰ *Id.*

¹⁰⁵¹ *See* OCA St. 7.

¹⁰⁵² OCA St. 1 at 40-41.

Other jurisdictions have employed a panoply of ratepayer protection mechanisms associated with decoupling. In a survey of commission decisions authorizing decoupling conducted by OCA witness Deupree, Mr. Deupree identified that other decoupling mechanisms have been approved with: limits to recovery or a cap on accruals; checks on over-earnings; demand-side management or energy efficiency targets; pilot or trial periods; and/or compliance reviews.¹⁰⁵³ By contrast, Columbia “proposes no ratepayer protection mechanisms typically approved as part of a decoupling mechanism.”¹⁰⁵⁴

Not only does the Company propose to continue business as usual under the RNA without meeting any sort of performance requirement, it proposes to do so without adequate customer protections. Under the proposed RNA, Columbia’s captive customers would be subject to an example of the monopolistic excess against which the Commission is designed to protect against.¹⁰⁵⁵ Columbia proposes no goals to achieve, no measures of success, and no ratepayer benefits associated with the proposed RNA. As a result, the proposed RNA should be denied.

3. Columbia is not entitled to a guarantee of recovering its costs and the RNA eliminates the Company’s incentive to control its costs between rate cases.

Columbia’s primary position is that the proposed RNA is necessary to ensure that it has a reasonable opportunity to recover its Commission-authorized revenue requirement.¹⁰⁵⁶ However, the Company confuses a “reasonable opportunity” with a

¹⁰⁵³ OCA Exh. MWD-9.

¹⁰⁵⁴ OCA St. 1 at 45.

¹⁰⁵⁵ *Pittsburgh v. Pa. PUC*, *supra*.

¹⁰⁵⁶ Columbia St. 17-R at 21.

“guarantee” in its case-in-chief. While Columbia is permitted a reasonable opportunity to recover its revenue requirement – including the potential for overearning if it behaves efficiently – it is not permitted a guarantee.¹⁰⁵⁷ As a result, the Company’s request to implement a revenue mechanism which seeks to set a floor of recovery at the Commission’s authorized levels of revenue runs counter to relevant constitutional law governing utility monopolies.

As stated above, the Commission in *PAWC 2023* found that PAWC’s proposed RDM “would produce guaranteed rate recovery where no guarantee existed in the past and shift the risk of recovery entirely onto customers without any benefit.”¹⁰⁵⁸ Due to the utility’s “frequency of filing base rate cases, along with its use of the FPFTY and the DSIC, we further find that PAWC has not demonstrated a need for the proposed RDM.”¹⁰⁵⁹ That same reasoning applies here, and Columbia has presented no sufficient basis to distinguish its proposed RNA from PAWC’s proposed decoupling mechanism.¹⁰⁶⁰

It is inequitable for only the Company to be able to benefit in the event of costs or revenues not materializing. When forming its general rate increase request, Columbia is permitted to include all revenues it anticipates collecting and all expenses that it anticipates

¹⁰⁵⁷ *Hope*, 320 U.S. at 603; *Pa. Elec. Co. v. Pa. PUC*, 502 A.2d 130, 133-35 (Pa. 1985) (determining just and reasonable rates does not require setting rates which are guaranteed to ensure continued net revenues).

¹⁰⁵⁸ *PAWC 2023* at 308.

¹⁰⁵⁹ *Id.*

¹⁰⁶⁰ While PAWC utilizes the DSIC to recover the cost of DSIC-eligible plant investment between rate cases and Columbia does not, this is largely due to the frequency of Columbia’s rate increase requests, which are more frequent than PAWC’s. As a result, Columbia’s lack of usage of the DSIC is not a sufficient distinguishing factor.

incurring during the FPFTY. Should expenses not materialize to the extent claimed by the Company, ratepayers are not able to recover their overpayment.¹⁰⁶¹

Instead, the Company is able to pocket the difference between its projected and actual expenses and retain those earnings, to the benefit of its shareholders. This provides an incentive for utilities to control costs and maximize net operating income. Should the proposed RNA be implemented, the Company's incentives to tighten its belt during periods of declining consumption will be reduced. Instead of implementing solutions which the Company has previously relied upon to address declining sales in its significant history of operating as an NGDC or to creatively address the issue in a proactive manner – such as refining its approach to infrastructure or expense planning – Columbia would prefer to remain impervious to changes in customer behavior.

As described *supra*, while the Company is technically correct that the proposed RNA does not guarantee earnings, the Company is only correct when looking at year one: any amount not collected through the RNA in the first year will be rolled over for collection in the second year.¹⁰⁶² The proposed RNA, unlike how the Company currently recovers demand- and throughput-related costs, is not volumetric and any customer receiving service from Columbia would pay the same amount each month towards the prior year's under-collection, meaning that there is virtually zero revenue risk because the RNA

¹⁰⁶¹ *Nat'l Fuel Gas Dist. Corp. v. Pa. PUC*, 464 A.2d 546, 567 (Pa. Cmwlth. Ct. 1983) (“[T]he Code does not authorize the imposition of a refund of excess revenues and improvident expenditures without consideration of the reasonableness and justice of the rates as a whole.”).

¹⁰⁶² Columbia St. 17-R at 21.

surcharge is unavoidable. Under the proposed RNA, demand- and throughput-related costs are recovered on a per-customer basis, contrary to principles of cost causation and the manner in which the Commission determined rate design in the Company's rate case.

Importantly, the proposed RNA reduces the beneficial effects of regulatory lag. Regulatory lag, as adjusted by the use of the FPFTY and the DSIC, can be beneficial to a utility and to its customers. Regulatory lag permits a utility to enjoy periods of overearning, during which time it can increase its operating efficiency and flow its savings and return directly to shareholders, which are uninterrupted until either it begins to under-earn or determines to file a rate increase request.¹⁰⁶³ This is especially true under the proposed RNA, when Columbia would be able to retroactively recover uncollected revenue during situations of overearning without regard for controlling its costs. During periods of underearning, regulatory lag disincentivizes utility overcapitalization, which, at the time that the utility next files a rate increase requests, results in a lesser rate base balance.¹⁰⁶⁴ This is, in part, why revenue decoupling is also paired with multiyear rate plans or other mechanisms which embed regulatory lag into the utility's earnings prospects.¹⁰⁶⁵ However, the disincentive to overcapitalize does not apply to reliability-related improvements, which are DSIC-eligible and, therefore, experience virtually zero regulatory lag in Pennsylvania.¹⁰⁶⁶ As a result, regulatory lag has no effect on utility reliability and safety improvements and is beneficial in the rate-setting context.

¹⁰⁶³ OCA St. 1 at 15.

¹⁰⁶⁴ OCA St. 1SR at 3-4.

¹⁰⁶⁵ *Id.*

¹⁰⁶⁶ *Id.* at 4-5.

There is no reasonable basis to conclude that the manner in which the Commission has designed rates previously – in the absence of revenue decoupling – prevents Columbia from a reasonable opportunity to earn a return on its rate base. Instead, the Company’s attempt to augment its current rate design with decoupling mechanisms addresses a problem which does not need to be resolved: retrospective recovery of costs which were not collected through rates designed in accordance with principles of cost causation. Therefore, the proposed RNA should be denied as an unfounded guarantee of earnings over time which Columbia does not require in order to have a reasonable opportunity to earn is Commission-authorized revenue requirement.

4. The proposed RNA is contrary to cost causation because it recovers demand- and throughput-related costs as a fixed, unavoidable charge.

The proposed RNA charges customers based on revenues which were not previously collected by the Company. However, rates are designed based on principles of cost causation, with a customer charge recovering direct customer-related costs and the volumetric charge recovering demand- and throughput-related costs.¹⁰⁶⁷ The proposed RNA is not based in recovering a particular category of cost consistent with cost causation; rather, the RNA paints with broad strokes to retroactively recover *any* cost which was not previously collected through a fixed monthly surcharge irrespective of the function of the cost recovered.¹⁰⁶⁸

¹⁰⁶⁷ OCA St. 4 at 14.

¹⁰⁶⁸ OCA St. 1 at 18.

In *PICGUG*, the Commonwealth Court recently determined that it is unclear whether “value of service” is consistent with cost causation and, therefore, it is unclear whether rates can be just and reasonable if they are premised on backwards-looking value of service principles.¹⁰⁶⁹ The proposed RNA directly violates this holding. Under the proposed RNA, all costs which were charged to customers in the year prior are deemed to be “fixed” even though “fixed” is not a category of cost causation, and costs recovered through the proposed RNA as a fixed surcharge may be throughput-related, such as mains costs, and are appropriately considered to vary with usage.¹⁰⁷⁰

Cost causation is a forward-looking exercise.¹⁰⁷¹ Rates should be designed to allocate to future beneficiaries of a system’s design and construction their fair share of their customer class’s costs.¹⁰⁷² The proposed RNA is, by contrast, designed to charge future customers for the revenue collected by past customers’ payment and usage patterns: it is not forward-looking, consistent with fundamental principles of cost causation, but pushes forwards the difference between the revenue the Company believes it is entitled to collect in comparison to that which it previously had a reasonable opportunity to collect.

As a result, the proposed RNA directly contradicts cost causation by (1) not targeting specific costs, such as customer-related costs, which a customer directly caused the system to incur but did not pay for and (2) not charging the same customer which caused the difference in revenue between the BRPC and ARPC their allocated share of that

¹⁰⁶⁹ *PICGUG*, 2025 Pa. Commw. LEXIS 133 at ** 1-2.

¹⁰⁷⁰ OCA St. 4 at 13.

¹⁰⁷¹ *PICGUG*, 2025 Pa. Commw. LEXIS 133 at * 39.

¹⁰⁷² *Id.*

difference. Due to the overly broad nature of the costs recovered under the proposed RNA, the RNA cannot be consistent with cost causation. It is insufficiently tailored to meet that aim.

5. **The proposed RNA is likely to produce a disincentive for customer conservation and energy efficiency because avoided distribution charges in one year results in RNA charges the following year; the RNA captures customers' bill savings earned through their reduced usage.**

Under the proposed RNA, the Company will be able to recover all distribution costs associated with customers' usage reduction from the year prior. While customers may be able to see the benefits of reduced usage through a reduction to their commodity costs, the experience of Columbia's customers indicates that commodity costs are a relatively small portion of their overall bill.¹⁰⁷³ After the first year that the proposed RNA is in effect, customers will begin to lose all benefits incurred in the year prior associated with their reduced usage due to the RNA surcharge for reduced consumption. In *PAWC 2023*, the Commission denied the requested decoupling mechanism, in part, because the proposed mechanism would erode customers' bill savings due to reduced consumption.¹⁰⁷⁴ Like in *PAWC 2023*, the only way for a Columbia customer to reduce their natural gas bill is to conserve energy.¹⁰⁷⁵

¹⁰⁷³ Tr. 167 (Witness Skvarla testified that, for his \$67 Columbia bill, only \$7 reflected the cost of the natural gas commodity consumer, with the remaining portion resulting from distribution charges).

¹⁰⁷⁴ *PAWC 2023* at 308.

¹⁰⁷⁵ *Id.*; see also OCA Exh. BA-5 (finding that residential natural gas customers that shop for a natural gas supplier significantly overpay for natural gas commodity charges, indicating that CHOICE is an ineffective way to reduce bills).

By implementing the RNA, the customer's distribution cost savings will be collected the following year, spread across all customers in their rate class. Customers will only see clear price signals resulting from conservation during the test period for the proposed RNA during which the ARPC is established; however, once the surcharge goes into effect, the customer's total bill may not decrease due to conservation proportionate to their conservation efforts.¹⁰⁷⁶ Indeed, one of the Company's primary motivations for pursuing the proposed RNA is due to customers' usage reduction efforts which cause actual throughput to dip below the throughput projections relied upon in setting base rates.¹⁰⁷⁷ Given the Company's intention to collect the distribution-related cost savings from customer conservation through the proposed RNA, the RNA is clearly designed to interfere with customers' attempts to reduce their bills by decreasing their consumption.

As stated by the Commission regarding PECO Gas's proposed WNA, under decoupling, "it will be difficult for consumers to gauge the return on investment for energy efficiency investments when their efforts to conserve energy are not clearly beneficial in reducing their costs."¹⁰⁷⁸ Even though PECO Gas made a similar argument to Columbia, that customers will still be able to see cost savings through a reduction in the commodity portion of their bills, the Commission still rejected the proposed WNA.¹⁰⁷⁹ Similarly, in *Columbia 2010*, the Commission rejected the Company's proposal to recover all distribution charges through a fixed customer charge because of the effect it would have

¹⁰⁷⁶ OCA St. 1SR at 15.

¹⁰⁷⁷ *Id.*

¹⁰⁷⁸ *PECO Gas 2024* at 97.

¹⁰⁷⁹ *Id.*

on customers' incentive to conserve energy.¹⁰⁸⁰ For all the reasons set forth above and because Columbia presented no meaningful basis to distinguish the proposed RNA from PAWC's proposed RDM, PECO Gas's proposed WNA, or Columbia's straight-fixed variable pricing model in *Columbia 2010*, regarding incentives to conserve energy and pursue energy efficiency, the Commission should deny Columbia's request to implement the proposed RNA.¹⁰⁸¹

6. Overall, Columbia has failed to meet its burden of proof that the RNA is a just and reasonable rate.

Under the Commission's policy factors, the proposed RNA would not result in just and reasonable rates.¹⁰⁸² The proposed RNA presents no potential for customer benefit while providing Columbia with a virtual guarantee to recover any revenues it did not collect in prior periods without consideration of the reason those costs were not collected. Columbia is not entitled to a guarantee to recover its authorized revenue requirement.¹⁰⁸³ It is especially not entitled to collect costs caused by customers' demand and throughput characteristics through a fixed surcharge that does not vary with usage.¹⁰⁸⁴ The proposed RNA will disproportionately harm Columbia's low-income customers and will reduce customers' agency to control their natural gas heating bills through reducing consumption.¹⁰⁸⁵

¹⁰⁸⁰ *Columbia 2010* at 51-52.

¹⁰⁸¹ *Dee-Dee Cab, Inc. v. Pa. PUC*, 817 A.2d 593, 598 (Pa. Cmwlth. 2003) (citing *Bell Atl.-Pa.*, *supra*) (the Commission is obligated to render consistent decisions).

¹⁰⁸² 66 Pa. C.S. § 1301; 52 Pa. Code §§ 69.3301-3302.

¹⁰⁸³ *Hope*, *supra*; *Bluefield*, *supra*.

¹⁰⁸⁴ *Lloyd*, 904 A.2d at 1020.

¹⁰⁸⁵ OCA St. 5 at 104-07.

Despite the myriad harms to consumers presented by the proposed RNA and the absence of potential benefits, the Company's request is further deficient because it has not proven that an RNA is required for the Company to have a reasonable opportunity to recover its revenue requirement.¹⁰⁸⁶ As in *PAWC 2023*, Columbia's frequent rate increase requests and the use of the FPFTY obviate any need for revenue decoupling.¹⁰⁸⁷ Columbia already charges residential customers the highest distribution rates in Pennsylvania and among the highest in the mid-Atlantic region.¹⁰⁸⁸

No evidence of record indicates that the Company is unable to continue to provide adequate, safe, and reliable service under traditional ratemaking or through the suite of alternative ratemaking mechanisms already available to distribution utilities in Pennsylvania (i.e., the FPFTY and DSIC).¹⁰⁸⁹ Despite declines in actual usage per customer in recent years, the Company's revenue per customer has increased, in part due to throughput growth from the connection of new customers.¹⁰⁹⁰ Columbia's ability to collect revenues appears to function just fine; however, OCA witness Deupree's review of the Company's historic earned return on equity indicates that the Company's challenges in earnings its authorized return stem from cost inefficiencies instead of insufficient revenues.¹⁰⁹¹

¹⁰⁸⁶ See *Columbia 2020* at 264-65.

¹⁰⁸⁷ *PAWC 2023* at 308.

¹⁰⁸⁸ OCA Exh. MWD-6.

¹⁰⁸⁹ OCA St. 1 at 29.

¹⁰⁹⁰ OCA St. 1 at 28-29; OCA Exh. MWD-5.

¹⁰⁹¹ OCA St. 1 at 27-28; OCA Exh. MWD-4.

Approval of the proposed RNA would not incentivize Columbia to address its cost inefficiencies. Instead, if the proposed RNA were approved, the Company would have reduced incentives to control costs because it bears less risk associated with revenue recovery and can rely on RNA charges to cover any cost inefficiencies.¹⁰⁹² Ratepayers would be harmed, not only because of the likelihood of higher bills under the RNA, but also because of the potential for Columbia to overcapitalize or become increasingly cost inefficient resulting in higher rates in any subsequent rate increase. In exchange for these potential harms, the proposed RNA provides no benefits: no reduction to return on equity, no performance-based goals, and no consumer protections against potentially significant RNA surcharges.

In sum, Columbia has failed to satisfy its burden of proof to demonstrate that the proposed RNA would result in just and reasonable rates. The proposed RNA is an example of a monopolistic excess as a revenue extraction mechanism designed to meet the aims of the Company regardless of the cost to consumers. The Commission, considering the interests of consumers, should not permit such excesses.¹⁰⁹³ Therefore, the OCA respectfully requests that the Commission deny Columbia's request for approval to implement the proposed RNA.

¹⁰⁹² OCA St. 1SR at 14-15.

¹⁰⁹³ 71 P.S. § 309-5.

XII. CUSTOMER/QUALITY OF SERVICE ISSUES

In this case, management quality, efficiency and effectiveness, and customer service issues exist, and they should be considered by the Commission in its setting of just and reasonable rates for Columbia’s customers.

Service¹⁰⁹⁴ must be adequate, efficient, safe, and reasonable.¹⁰⁹⁵ In setting just and reasonable rates, the Commission “shall consider...the efficiency, effectiveness and adequacy of service of each utility.”¹⁰⁹⁶ The Commission can direct the adequate, reasonable, safe, sufficient service to be observed and furnished by the utility.¹⁰⁹⁷ 6 The Commission can order improvements to service as a condition of any rate increase.¹⁰⁹⁸ The Commission has recently and properly recognized that “[a] base rate proceeding ‘is the proper venue for hearing [] customer service issues.’”¹⁰⁹⁹ In the 2023 PGW base rate case, the Commission explicitly identified that the following factors were relevant

¹⁰⁹⁴ “Service” is used broadly and inclusively, and captures “any and all acts done, rendered, or performed” by public utilities. 66 Pa. C.S. § 102; *West Penn Power Co. v. Pa. PUC*, 578 A.2d 75, 77 (Pa. Cmwlth. Ct. 199)). As such, all parts of a public utility’s customer service must be adequate in order for the utility to comply with the requirements of Section 1501 of the Code, and “inappropriate and unreasonable treatment to customers can be interpreted as inadequate service.” See, e.g., *Laura Andracchio Johnson and Charles Johnson v. Duquesne Light Co.*, Docket No. C-2022-3032695, 2023 PA. PUC LEXIS 343 at *17, Order (Dec. 21, 2023) (citing *Barbara R. Lolly v. Duquesne Light Co.*, Docket No. C-2010-2167824, Order (May 9, 2011)).

¹⁰⁹⁵ 66 Pa. C.S. § 1501.

¹⁰⁹⁶ 66 Pa. C.S. § 523.

¹⁰⁹⁷ 6 Pa. C.S. §§ 1504, 1505.

¹⁰⁹⁸ *Pa. PUC v. Pa. Gas & Water Co.*, 74 PUR4th 238, 244-45 (1986) (PG&W 1986); *Pa. PUC v. Phila. Gas Works*, 2000 Pa. PUC LEXIS 876, *41-44, Order (Nov. 22, 2000) (*PGW 2000*).

¹⁰⁹⁹ *PUC v. Phila. Gas Works*, 2023 PA. PUC LEXIS 93, Order at 193 (April 20, 2023)(*PGW 2023*).

considerations in evaluating whether PGW’s proposed rates were just and reasonable: (1) PGW’s management quality, efficiency, and effectiveness; (2) service quality and reliability; and (3) effect on universal service.¹¹⁰⁰ The Commission may also condition a portion of a utility’s requested rate increase on its compliance with service adequacy objectives.¹¹⁰¹

The burden of proof to demonstrate that a public utility’s services are adequate is on the utility; other parties are not required to demonstrate the utility services are inadequate for the Commission to decide that such is the case.¹¹⁰²

The OCA offers the following recommendations for improvements in Columbia’s quality of customer service and asks that they be imposed as conditions of any rate increase awarded to Columbia.

A. Columbia should perform a root cause analysis to address customer disputes.

The OCA recommends that Columbia be required to develop and implement a root cause analysis of customer disputes, informal and formal complaints, and BCS findings,

¹¹⁰⁰ *PGW 2023* at 193-194, citing 52 Pa. Code §§ 69.2703(a)(6)-(8). Although the Commission’s citation was made in the context of a Policy Statement applicable to PGW’s cash flow ratemaking method, it would be antithetical to public policy and the principles of just and reasonable ratemaking to determine that Columbia’s status as an investor-owned utility somehow exempts it from meeting these standards. On the contrary, since Columbia is seeking a management performance award of 25 basis points, scrutiny of the ratemaking considerations identified for PGW becomes even more important in this case.

¹¹⁰¹ *Nat’l Utils. v. Pa PUC*, 709 A.2d 972, 977-78 (Pa. Cmlwth. Ct. 1998) (quoting *D.C. Transit System, Inc. v. Wash. Metro. Transit Comm’n*, 466 F.2d 394, 417 (D.C. Cir. 1972)).

¹¹⁰² 66 Pa. C.S. § 315(c); *Pa. PUC v. Duquesne Light Co.*, Docket No. R-2021-3024750, Order at n. 14 (Dec. 16, 2021) (“While Section 315(a) addresses the utility’s burden with respect to ‘rates,’ Section 315(c) also places on the utility the burden to show that the service and facilities it provides are ‘adequate, efficient, safe, and reasonable [.]’”

particularly those identified as “verified” and “infractions” on a regular basis.¹¹⁰³ The analysis should be developed in consultation with stakeholders within six months of the adoption of the final order in this proceeding.¹¹⁰⁴ The type of analysis recommended does not focus merely on individual complaints but requires a system-wide deep dive into trends and the underlying causes in order to identify specific improvements or changes with ongoing monitoring and evaluation of next steps.¹¹⁰⁵

OCA witness Alexander identified concerns with the process that Columbia uses to handle customer complaints because the Company does not conduct analysis of customer complaint trends. OCA witness Alexander testified:

Columbia has a database that contains closed customer disputes and the results of BCS informal complaints, but there is no evidence of analysis of trends or internal actions undertaken in response to this information. Columbia has not conducted a root cause analysis of customer complaint trends. Rather, than undertaking an analysis of complaints, complaint trends, and identifying system wide solutions or defects in training materials, the Company’s response is “A formal root cause analysis was not conducted on customer disputes or complaints. However, the Company’s Regulatory Compliance department does meet regularly with its call center and other customer facing departments to discuss complaint issues and concerns. Based on these meetings, refresher training and/or individual coaching is performed. There is no internal document that reflects an analysis of trends and issues, documents the root cause, or reflects documented changes to processes or system. The Company does review any BCS finding of infractions on a case by case basis. However, the example included in this data response (a defective denial of service letter) was documented by the BCS and not the Company prior to the BCS analysis of customer complaints. Furthermore, the Company has not conducted any audit or investigation of its call center to determine overall compliance with Pennsylvania customer service and consumer protection regulations.”¹¹⁰⁶

¹¹⁰³ OCA St. 6 at 17.

¹¹⁰⁴ OCA St. 6 at 17, Exh. BA-3 (example of a proper root cause analysis).

¹¹⁰⁵ OCA St. 6 at 17.

¹¹⁰⁶ OCA St. 6 at 15-16.

OCA witness Alexander testified that she believed that this lack of proper analysis and response to customer complaints and lack of proactive oversight of the call center virtual operations was a significant defect in Columbia’s customer service program.¹¹⁰⁷

Ms. Alexander testified:

Public utilities should conduct regular reviews of internal disputes and informal complaints and compliance related responses from BCS to identify “red flags” and seek out indicators that suggest the need for revision of internal training or the development of new policies and programs to ensure compliance with Chapter 56. Focusing solely on looking at individual complaints fails to recognize that a single complaint may reflect a more serious problem or concern.¹¹⁰⁸

OCA witness Alexander testified that she was particularly concerned with the “lack of regular audits or evaluations of the call center operations that are located in several states, serve several states and are 100% virtual, a structure that suggests a more proactive oversight is called for.”¹¹⁰⁹

Columbia witness Paloney rejected OCA witness Alexander’s recommendation in her Rebuttal Testimony.¹¹¹⁰ She attached Exhibit NP-2R to her Rebuttal Testimony, but that exhibit confirms that Columbia only collects complaint data by “reason.” As OCA witness Alexander testified, “there is no information in her exhibit that reflects an analysis, let alone a root cause analysis...”¹¹¹¹ Ms. Alexander further explained the deficiencies with the Company’s approach:

¹¹⁰⁷ OCA St. 6 at 16.

¹¹⁰⁸ OCA St. 6 at 16.

¹¹⁰⁹ OCA St. 6 at 16.

¹¹¹⁰ Columbia St. 9-R at 24.

¹¹¹¹ OCA St. 6SR at 9.

[w]hile collecting data on the categories of customer complaints is a part of a root cause analysis, that is only the first step. The next steps are to explore trends in complaints, find the root cause of complaints that are similar and repeated, explore possible solutions to prevent complaints or reduce trends that can be impacted by training, changes in policies, and additional management oversight, monitor the results of actions taken based on the root cause analysis, and routinely explore complaint data on a regular basis.¹¹¹²

Columbia witness Paloney’s response “reflects a lack of knowledge of the process and ignores the potential benefits.”

The Company also misunderstood Ms. Alexander’s recommendation that “each and every individual complaint” would be the subject of a root cause analysis.¹¹¹³ Instead, the purpose of the analysis is to take data gathered by the Company about the “reasons” for customer complaints and explore and analyze that data.¹¹¹⁴ OCA witness Alexander cited to an example of how a root cause analysis could have been used to address a series of complaints:

[f]or example, had Columbia taken a root cause analysis approach to the pattern of improper denial of service communications that appeared in their internal disputes prior to the customer appealing those results to the BCS, the Company could have identified the need for internal reforms prior to waiting to be notified by the BCS and triggering Columbia’s response. Instead, Ms. Paloney relies on this prompt response to change the denial of service letter based on BCS communications as an example of a proper action, thus missing the basic purpose and point of my recommendation.¹¹¹⁵

The OCA recommends that Columbia be required to develop and implement a more rigorous root cause analysis of customer disputes, informal and formal complaints, and

¹¹¹² OCA St. 6SR at 9.

¹¹¹³ OCA St. 6SR R at 10, citing Columbia St. 9-R at 24.

¹¹¹⁴ OCA St. 6SR at 10.

¹¹¹⁵ OCA St. 6 at 10; Columbia St. 9-R at 25.

BCS findings, particularly those identified as “verified” and “infractions” on a regular basis.¹¹¹⁶ The analysis should be developed in consultation with stakeholders within six months of the adoption of the final order in this proceeding.¹¹¹⁷ The Company should initiate this routine process within six months of a final order in this base rate proceeding after consultation with stakeholders on the design and implementation of a proper root cause analysis.¹¹¹⁸

B. Columbia should perform an analysis of payment arrangement policies and termination and reconnection policies.

Columbia should routinely evaluate its payment arrangements to identify the factors that contribute to the success or failure of its agreements and take steps to internalize the results of that analysis in its implementation of payment arrangements and communications with customers. In addition, the Company’s failure to evaluate its termination and reconnection of service results may contribute to higher uncollectible costs and should also be the subject of routine analysis to consider policies and programs to explore the potential for more effective payment strategies.

The OCA recommends that the Company be required to evaluate and report on its payment plans, their policies, and identify potential reforms and changes that are likely to ensure a greater success with payment plans.¹¹¹⁹ This could help to reduce collection costs and future terminations of service with a resulting lower uncollectible expense. The OCA

¹¹¹⁶ OCA St. 6 at 17.

¹¹¹⁷ OCA St. 6 at 17, Exh. BA-3 (example of a proper root cause analysis).

¹¹¹⁸ OCA St. 6SR at 9.

¹¹¹⁹ OCA St. 6 at 17.

submits that it is unreasonable to approve Columbia's proposed uncollectible expense when the Company does not undertake any reasonable steps to evaluate the success or failure of its payment arrangements.¹¹²⁰

OCA witness Alexander examined in her Direct Testimony the problems with the Company's payment arrangements. She testified:

[w]ith regard to Payment Arrangement Requests (PARs are customer informal complaints to BCS about the terms of the utility's payment arrangement). BCS determined 4.3% were "justified," a result above the average of other gas utilities, reflecting an upward trend in PARs overall and those found to be "justified." Columbia's justified PAR rate increased from .03 in 2021 to .06 in 2023.¹¹²¹

As discussed below in the Universal Services section, Ms. Alexander's concerns are further confirmed by the problems similarly identified in the BCS report regarding low-income customer payment arrangements and termination and reconnections as identified by OCA witness Colton.

At present, Columbia does not evaluate the success or failure of its payment arrangements, and the Company has not undertaken any analysis of its termination and reconnection results.¹¹²² Columbia takes a similar approach to its payment arrangements as it does to its evaluation of customer complaints as discussed *supra*. OCA witness Alexander testified that "the Company's approach does not reflect any responsibility or

¹¹²⁰ OCA St. 6 at 18.

¹¹²¹ OCA St. 6 at 14-15.

¹¹²² OCA St. 6 at 17.

interest in determining the factors that lead to success or failure of its payment plan policies or the results of its termination and reconnection service policies.”¹¹²³

Columbia witness Paloney objected to the OCA’s recommendation that the Company evaluate plans on the grounds that their payment policies “strictly adhere” to the Commission’s regulations, but this ignores the evidence of the issues that Columbia is experiencing. OCA witness Alexander testified:

[t]he purpose of my recommendation is not to determine if Company is violating any Commission rule, but to evaluate whether the payment plans are successful and whether internal training, additional customer education, or other potential policy changes that might improve their success rate. Such an evaluation might also explore why the Company’s PARs increased based on the UCARE data.¹¹²⁴

The OCA recommends that the Company should evaluate the results of its termination and reconnection of service policies as a crucial component of determining the reasonableness of bad debt.¹¹²⁵

OCA witness Alexander reviewed Columbia’s written instructions and training materials for its field representatives during the termination process.¹¹²⁶ In particular, as discussed in the Confidential version of her testimony, OCA witness Alexander identified concerns that important consumer protections are not identified or implemented in Columbia’s training materials.¹¹²⁷ OCA witness Alexander testified regarding the training materials **BEGIN CONFIDENTIAL:**

¹¹²³ OCA St. 6 at 17.

¹¹²⁴ OCA St. 6SR at 11.

¹¹²⁵ OCA St. 6 at 18.

¹¹²⁶ OCA St. 6 at 18.

¹¹²⁷ OCA St. 6 (Confidential version) at 18-19.

END CONFIDENTIAL¹¹²⁸

Columbia witness Paloney also rejected the OCA's recommendations because of the Company's pre-termination steps taken.¹¹²⁹ Ms. Paloney incorrectly interpreted Ms. Alexander's recommendation to mean that the field service employees should be required to "reiterate" all of the applicable customer rights that might be alleged by the customer or responsible adult at the door prior to termination.¹¹³⁰ OCA witness Alexander testified:

[w]hile employees may or may not recite these rights, it is vital that the field representatives recognize all the potential customer rights that may be raised by the customer or responsible adult and take the appropriate steps to recognize those rights and respond with appropriate actions.¹¹³¹

Ms. Alexander is instead recommending that the Company appropriately educate and train its field personnel on all potential rights that may be encountered and how to respond. She testified "the obvious interpretation when the training materials fail to describe and recognize these rights is that the field representatives may not recognize or properly respond when those rights are alleged."¹¹³²

Columbia witness Paloney also raised a privacy and safety concern about having discussions about the customer's personal situation. OCA witness Alexander agreed that of course, to the extent that a field representative feels unsafe, they should withdraw. The

¹¹²⁸ OCA St. 6 at 18.

¹¹²⁹ Columbia St. 9-R at 26.

¹¹³⁰ Columbia St. 9-R at 26.

¹¹³¹ OCA St. 6SR at 12-13.

¹¹³² OCA St. 6SR at 13.

purpose of Ms. Alexander's recommendation is not to violate the customer's privacy or to put the field representative in an unsafe situation. The flipside is also true. To the extent that the customer may feel unsafe in raising their rights, that can be resolved by withdrawing from the termination and referring the customer to the call center for further discussion.¹¹³³ The field service representative should always bear in mind that the purpose of the contact is to terminate essential natural gas service for every member of the household and should be trained appropriately to respond to the rights that the Commission has ordered its public utilities to implement.¹¹³⁴

The OCA recommends that the Company should evaluate the results of its termination and reconnection of service policies as a crucial component of determining the reasonableness of bad debt.¹¹³⁵ As a result of her review, Ms. Alexander recommended that the Company revise its training materials to comply with all the applicable consumer protections and rights for residential customers facing termination of service. She recommended that the training materials should be improved to reflect the full range of customer rights associated with termination of service. She also recommended that additional regular reporting should be developed to allow management to track the implementation of this policy and its results once an attempt at contact has been achieved in consultation with stakeholders within 6 months of the final order in this proceeding.¹¹³⁶

¹¹³³ OCA St. 6SR at 13.

¹¹³⁴ OCA St. 6SR at 13.

¹¹³⁵ OCA St. 6 at 18.

¹¹³⁶ OCA St. 6 at 19.

C. Columbia Billing and Payment Policies

1. Columbia should ensure that appropriate billing disclosures and notifications are provided for Natural Gas Suppliers.

The OCA recommends additional educational shopping information be provided to customers by Columbia in light of the potential impact on customer bills and the risk to customers of termination due to inability to pay higher prices. OCA witness Alexander reviewed sample bills issued by Columbia to residential customers that include charges by a Natural Gas Supplier (NGS).¹¹³⁷ OCA witness Alexander attached a sample bill as Exhibit BA-4. She concluded that:

This bill properly educates the customer about the comparison of the NGS charges with the Price to Compare (natural gas supply prices and charges provided pursuant to the approved Default Service procurement plan). In this customer bill, the disclosure of the PTC is located near the presentation of the NGS charges.¹¹³⁸

Ms. Alexander identified that the customer's charges on the sample bill for the NGS are several times in excess of the applicable PTC.

OCA witness Alexander also included as Exhibit BA-5 an analysis that reflects the NGS charges actually billed to their customers by Columbia and provides the most accurate picture of bill impacts rather than relying on published NGS prices.¹¹³⁹ Ms. Alexander testified:

[a]s documented in this analysis, Columbia's residential (and non-residential) customers are vastly overpaying for essential natural gas supply when choosing an NGS instead of relying on the Price to Compare. From January 2022 through March 2025, approximately 48,000 residential

¹¹³⁷ OCA St. 6 at 20, Exh. BA-4.

¹¹³⁸ OCA St. 6 at 20.

¹¹³⁹ OCA St. 6 at 20, Exh. BA-5.

customers paid \$35,332,095 MORE than the PTC. In only two months was there even a slight benefit from NGS prices.¹¹⁴⁰

OCA witness Alexander identified concerns that the Company has not taken action in light of the adverse impact to customer bills. Ms. Alexander testified:

[i]t is the Company's position that they are following the customer choice program and it is not their responsibility to inform customers of their overpayment even when Columbia is billing and collecting these higher bills with the potential consequence of inability to pay, the need for payments arrangements, disputes, and termination of service for nonpayment.¹¹⁴¹

Columbia witness Kempic rejects OCA witness Alexander's recommendation and states that the Company has no obligation to conduct educational actions for customers paying significantly higher prices for NGS prices compared to default service.¹¹⁴² OCA witness Alexander testified:

Mr. Kempic's basis for rejecting my recommendation is that the Company is not required to take any action to educate its consumers who are paying higher prices and potentially suffering collection actions, such as late payment fees, engaging with Columbia to obtain a payment plan, receiving a termination notice and follow-up communications, termination itself, and contributing to the Company's uncollectible expense. There is no basis for Mr. Kempic's view that Columbia needs a "regulation" or "order" to take responsible action to assist customers who may not be aware of or understand the higher prices being paid.¹¹⁴³

Ms. Alexander testified that currently the customer service representatives are required to read and solicit the customer's interest in a "choice packet" but no regulation or order requires this action.¹¹⁴⁴ As Ms. Alexander concluded, "the Company promotes

¹¹⁴⁰ OCA St. 6 at 21.

¹¹⁴¹ OCA St. 6 at 21 (footnote omitted).

¹¹⁴² Columbia St. 1-R at 20-21; OCA St. 6 at 21; OCA St. 6SR at 14.

¹¹⁴³ OCA St. 6SR at 14.

¹¹⁴⁴ *Id.*

choice and appears to take no responsibility when customers end up paying higher bills issued by Columbia on behalf of participating suppliers.”¹¹⁴⁵

The Commission has previously issued orders affirming the adverse impact of customer choice shopping on low-income customers and the evidence that these customers pay higher prices for essential utility service when served by retail suppliers.¹¹⁴⁶ OCA witness Alexander testified that “Columbia should exclude known low income customers from customer choice if it has not already done so.”¹¹⁴⁷

The OCA recommends that Columbia take some action in light of the impact on customer bills who are paying higher prices compared to default service and who will be at risk for potential collection and termination of service from Columbia for inability to pay higher prices. At a minimum, Columbia should target educational messages to the choice customers to emphasize how to compare NGS charges per therm to the PTC and to urge them to compare prices and rates on a monthly basis.¹¹⁴⁸

2. Columbia Website and Automated Service Offerings

Columbia has begun to implement automated “chat boxes” and other electronic tools to engage with a customer’s account and eliminate calls to the call center. In a response to discovery request, OCA Set 03-82, Columbia stated:

Our Columbia mobile app has had more than 724,444 downloads since it launched in August 2021, and we have recorded more than 352,000 Start, Stop & Move transactions through the Service Request Module since it went live in April 2021. These self-service options are providing customers with

¹¹⁴⁵ *Id.*

¹¹⁴⁶ OCA St. 6SR at 15.

¹¹⁴⁷ OCA St. 6SR at 15.

¹¹⁴⁸ OCA St. 6 at 21.

a quick and easy way to service their Columbia account – on their own time schedules – without necessitating a call to the call center.¹¹⁴⁹

Ms. Alexander agreed that to the extent that these mechanisms provide a customer accurate information about their account status, the tools can be useful. OCA witness Alexander testified:

[h]owever, there are aspects to these automated interactions that raise concerns about the application of the consumer protections required by Chapter 56. For example, one of the automated scripts used in the IVR guides a customer to start new service and determines whether a security deposit is required. However, this script does not provide the customer the right to avoid a security deposit if qualified as low income and apparently relies on the customer to dispute or refuse the proposed deposit without any affirmative notice of this right.¹¹⁵⁰

The OCA recommends that the Commission should require Columbia to review its scripts for any automated chat box or “app” to ensure that all the customer rights associated with these transactions are provided for customers. The results of the analysis should then be reported to the stakeholders within six months after the final order of this proceeding.¹¹⁵¹

In her Rebuttal Testimony, Company witness Paloney agreed to conduct a review of the “workflow and scripting regarding consumer protections and will report its findings to the Universal Service Advisory Council, within six months of the final Order of this proceeding.”¹¹⁵² OCA witness Alexander agreed that this responded to the issue that she raised in her Direct Testimony concerning the example of the automated script to determine whether a security deposit would be required upon application of service that did not reflect

¹¹⁴⁹ OCA St. 6 at 22.

¹¹⁵⁰ OCA St. 6 at 22.

¹¹⁵¹ OCA St. 6 at 22; OCA St. 6SR at 15.

¹¹⁵² Columbia St. 9-R at 27.

the right of low income customers to be exempt.¹¹⁵³ OCA witness Alexander stated that “since the Company has properly recognized this concern, Columbia should initiate this review immediately and not wait for the final order in this proceeding.”¹¹⁵⁴

XIII. UNIVERSAL SERVICE PROGRAMS

A. Introduction

As discussed below, Columbia must make certain adjustments to its treatment of low-income customers, both confirmed low-income customers and unconfirmed low-income customers. Rates set in this proceeding must be just and reasonable, which requires balancing the interests of all customers, including low-income residential consumers, with the interests of the Company.¹¹⁵⁵ There are few considerations as important as affordability, as affordability “is in both the shareholder and ratepayers’ best interest. Affordable bills will maximize revenues for the Company and will enable ratepayers to continue to receive an essential service.”¹¹⁵⁶

Affordability for low-income customers is a paramount rate consideration. The Code “seeks to ensure that service remains available to all customers on reasonable terms and conditions.”¹¹⁵⁷ NGDCs, specifically, are required to assist low-income customers with affording their natural gas service.¹¹⁵⁸ NGDCs are obligated to provide service to their low-

¹¹⁵³ OCA St. 6SR at 16.

¹¹⁵⁴ OCA St. 6SR at 16.

¹¹⁵⁵ *Pittsburgh v. Pa PUC*, 126 A.2d 777, 794-85 (Pa. Super Ct. 1956).

¹¹⁵⁶ *Pa. PUC v. Roaring Creek Water Co.*, 73 Pa. PUC 373, 400 (1990) (*Roaring Creek 1990*).

¹¹⁵⁷ 66 Pa. C.S. § 1402(3).

¹¹⁵⁸ 66 Pa. C.S. § 2203(7)

income customers which increases affordability – even if the customers are not enrolled in the NGDC’s customer assistance program – and reduces the accrual of arrearages and number of terminations.

Columbia’s heating bills were 96% higher in 2025 than they were in 2012.¹¹⁵⁹ The Company has also filed and received ten rate increases since 2009, with five of them in the last six years.¹¹⁶⁰ The Company has again filed an additional request for \$110.5 million increase in this proceeding. As discussed below, the Commission’s affordability benchmark, that a natural gas bill should occupy no more than 6% of a CAP-qualifying customer’s monthly income will be far exceeded for the Company’s customers who earn at or below the lowest quintile of income customers in the Company’s service territory. As a result, it is essential that the Commission act to protect the Company’s customers who may not be able to afford service. In addition to recommending the Commission adopt an overall lower revenue requirement increase that will allow the Company to recover its reasonable costs and result in a lower rate increase, the OCA identified several areas where the Company could improve its protections for low-income customers and urges the Commission to adopt these protections to remove service barriers for Columbia’s most vulnerable customers.

Furthermore, service must be adequate, efficient, safe and reasonable.¹¹⁶¹ In setting just and reasonable rates, the Commission “shall consider...the efficiency, effectiveness

¹¹⁵⁹ OCA St. 5 at 11.

¹¹⁶⁰ OCA St. 5 at 8.

¹¹⁶¹ 66 Pa. C.S. § 1501.

and adequacy of service of each utility.”¹¹⁶² The Commission can order improvements to service as a condition of any rate increase.¹¹⁶³ The Commission can direct the adequate, reasonable, safe, sufficient service to be observed and furnished by the utility.¹¹⁶⁴

The law requires quality of service and affordability of service as a part of setting rates. Through this lens, OCA witness Colton examines the impact of the proposed rate increase on the overall affordability of Columbia’s current and proposed rates, the affordability for low-income and moderate income ALICE households, the impact on the cost-of-living for customers including the impact of inflation not just on the utility but on ratepayers, and recommends modifications to the Company’s universal service programs in order to improve affordability considerations.

B. The Commission must consider as a part of this rate request the overall affordability of Columbia’s rates.

Columbia has filed for rate increases ten times since 2009, with requested (and granted) rate increases in 2019,¹¹⁶⁵ 2020,¹¹⁶⁶ 2021,¹¹⁶⁷ 2022,¹¹⁶⁸ and 2024,¹¹⁶⁹. Columbia again requests an additional \$110.5 million distribution rate increase in the instant proceeding. OCA witness Colton examined the impact of the repeated rate increases on the overall affordability for low-income customers. Mr. Colton testified:

¹¹⁶² 66 Pa. C.S. § 523,

¹¹⁶³ *PG&W 1986* at 244-245; *PGW 2000* *41-44.

¹¹⁶⁴ 66 Pa. C.S. §§ 1504, 1505.

¹¹⁶⁵ *Pa. PUC v. Columbia Gas Co.*, Docket No. R-2019-3010039, Order (Oct. 3, 2019)

¹¹⁶⁶ *Pa. PUC v. Columbia Gas Co.*, Docket No. R-2020-3018835, Order (April 15, 2021)

¹¹⁶⁷ *Pa. PUC v. Columbia Gas Co.*, Docket No. R-2021-3024296, Order (Dec. 16, 2021)

¹¹⁶⁸ *Pa. PUC v. Columbia Gas Co.*, Docket No. R-2022-3031211, Order (Dec. 8, 2022)

¹¹⁶⁹ *Pa. PUC v. Columbia Gas Co.*, Docket No. R-2024-3046519, Order (Nov. 22, 2024)

when looking at rates over time, Columbia's low-income customers are facing increasingly unaffordable heating burdens given the Company's ongoing rate increases. For Columbia's lowest income customers (with income levels at the lowest range of the Federal Poverty Level (FPL) (0 – 50%)), heating burdens are significantly higher than the affordable burden defined by the PUC of 4% of income. For Columbia's other customers in the mid (50%-100% FPL) and highest (100-150% FPL) ranges of what is considered low-income, the heating burdens under Columbia's rates exceed the affordable burden defined by the PUC of 6% of income.¹¹⁷⁰

In particular, Mr. Colton found as discussed in Table 1 of his Direct Testimony a significant impact on energy affordability for low-income customers. OCA witness Colton testified:

- At the lowest range of FPL (0 – 50%), heating burdens significantly exceed the affordable 4% of income definition. While heating burdens were 10.6% in 2012, those burdens had increased to 12.9% in 2024, and increased further to 14.9% in 2025. In 2025, heating burdens for Columbia's lowest income customers were more than three and a half times higher than the affordable burden defined by the PUC, while in 2024, they were more than three times higher than the affordable burden.
- In the mid-range (50 – 100% FPL), heating burdens for Columbia's customers exceeded the affordable burden of 6% of income beginning in 2014, and became increasingly unaffordable through 2025 at 7.9%.
- At the highest FPL range (100 – 150% FPL), while heating burdens were 3.4% in 2012 and 2013, they had increased to 5.3% of income by 2023, before somewhat declining through 2025. However, bills for this group of customers does not exceed the PUC's 6% of income definition for affordable burden.¹¹⁷¹

Mr. Colton noted that the perceived improvement in affordability for households between 100-150% of the FPL “may be somewhat misleading.”¹¹⁷² Mr. Colton testified:

¹¹⁷⁰ OCA St. 5 at 8.

¹¹⁷¹ OCA St. 5 at 8.

¹¹⁷² OCA St. 5 at 9.

Net household resources will not necessarily increase as household income increases. As the household becomes higher and higher, for example, households increasingly lose access to supplements. These non-cash, supplemental benefits (e.g., Food Stamps, housing and medical assistance) are not counted as “income” in determining program eligibility for other assistance programs. The loss of such benefits reduces the ability of a household to pay its home energy bills.¹¹⁷³

OCA witness Colton’s testimony addresses the steady impact of increases in natural gas prices and finds that “all-in-all, the data above demonstrates that the Company’s heating bills were 96% higher in 2025 than they were in 2012” while “incomes at the various ranges of FPL only rose 40% higher since 2012.”¹¹⁷⁴ As Mr. Colton demonstrates in Figure 1 of his testimony, “after a dip in the Company’s natural gas heating bills in 2016, gas prices again began to increase, with a sharp increase in 2022, which has not abated.”¹¹⁷⁵ The Company has had four distribution base rate increases since 2019, and the current filing would be fifth, if approved.¹¹⁷⁶ As Mr. Colton testifies:

the proposed increase in rates in this case will drive bills even higher. During the most recent three-year period shown in the graph, heating burdens at 50-100% FPL exceeded the affordable 6% of income burden defined by the PUC. At the lowest end of the FPL range (0-50% FPL), heating burdens in these three recent years were from three to four times higher than the 4% of income level defined by the PUC to be affordable.¹¹⁷⁷

Mr. Colton testified that the data he examined demonstrates that the Company’s heating bills were 96% higher in 2025 than they were in 2012.¹¹⁷⁸ In contrast, the incomes

¹¹⁷³ OCA St. 5 at 10.

¹¹⁷⁴ OCA St. 5 at 11 (footnote omitted).

¹¹⁷⁵ OCA St. 5 at 10.

¹¹⁷⁶ OCA St. 5 at 10.

¹¹⁷⁷ OCA St. 5 at 10.

¹¹⁷⁸ OCA St. 5 at 11.

at the ranges of the Federal Poverty Level (FPL) only rose 40% higher since 2012.¹¹⁷⁹ OCA witness Colton concluded that “Columbia’s low-income customers are facing increasingly more unaffordable natural gas heating burdens given the Company’s ongoing rate increases.”¹¹⁸⁰

For the reasons set forth above, the Commission must consider the impact of affordability of the rates on customers, particularly low-income households. Columbia’s frequent rate proceedings and resultant rate increases have created an affordability problem and rates for customers have drastically increased.

C. The Commission must also consider the impact on affordability for low-income households.

Columbia’s frequent rate increases have created a paradox in which the Company’s rates are not affordable for many of its most vulnerable low-income customers. OCA witness Colton testified:

The PUC has defined an affordable burden for households with income between 50% and 150% of FPL and heating with natural gas to be 6% of income. The PUC defined an affordable burden for households with income less than 50% of FPL and heating with natural gas as being no more than 4% of income.¹¹⁸¹

OCA witness Colton utilizes this 4% burden in his analysis of the impact on affordability.¹¹⁸²

¹¹⁷⁹ *Id.*

¹¹⁸⁰ *Id.*

¹¹⁸¹ OCA St. 5 at 16.

¹¹⁸² OCA St. 5 at 16.

OCA witness Colton examined the movement in Columbia's prices relative to the movement in Columbia's customers' incomes.¹¹⁸³ After completion of a Price Index based upon the data reported in the PUC's annual rate comparison report, Mr. Colton found that Columbia's prices declined somewhat from 2014 to 2016, but that in 2016 Columbia's prices dramatically increased and have continued to increase.¹¹⁸⁴ For his analysis, Mr. Colton overlaid the Price Index compared to an income index for the same time period to inform the affordability analysis for Columbia.¹¹⁸⁵ The analysis showed that in none of the 26 Columbia counties did the growth for Q1 income [lowest income customers] exceed the growth in Columbia's rates from 2014 through 2023. OCA St. 5 at 13-14, Figure 3.

His analysis also showed that:

the Columbia Gas prices grew faster than the Q2 incomes [the next higher level of income] grew during this period.¹¹⁸⁶

The bottom line observation is that the 40% of the customers with Columbia Gas with the lowest incomes throughout its service territory were worse off in 2023 than they were in 2014 when comparing incomes to Columbia Gas prices.¹¹⁸⁷

The mismatch between the growth in Q1 incomes and the growth in the Columbia prices means that Columbia bills are taking up a higher and higher percentage of the customer's total household income. OCA witness Colton is assessing the increase by

¹¹⁸³ OCA St. 5 at 1-27. For his analysis of affordability, Mr. Colton examines the incomes of moderate and low-income customers. OCA St. 5 at 11-12.

¹¹⁸⁴ OCA St. 5 at 12-13, Figure 2.

¹¹⁸⁵ OCA St. 5 at 13. H

¹¹⁸⁶ OCA St. 5 at 14.

¹¹⁸⁷ OCA St. 5 at 15.

measuring what increase in household income would be needed to allow the households to experience an affordable bill each year.¹¹⁸⁸

Using the 4% energy burden, OCA witness Colton found that the Bill-to-Income ratios for Q1 income are unaffordable throughout the Columbia service territory and have grown “substantially more unaffordable in the time period 2014 through 2023.”¹¹⁸⁹ He next examined the impact of the rate increase proposed in this proceeding on the affordability of bills in the Columbia service territory. Mr. Colton testified:

[t]he data shows not only the deep unaffordability facing the lowest income households in the Columbia Gas service territory at existing rates, but also the extent to which that unaffordability will increase should the rates proposed in this proceeding be adopted. Households with income less than \$10,000, for example, experience a Columbia Gas bill burden of 30.0% under existing rates, with that burden increasing to 33.7% under the proposed rates holding usage constant (at Columbia’s mean residential usage). Even with income as high as \$25,000 to \$29,999, Bill-to-Income ratios nearly exceed the level defined by the Commission to be affordable (6%) at the mean usage and existing rates and do exceed the affordable 6% level at proposed rates.¹¹⁹⁰

There are variations in Bill-to-Income ratios from year to year, as actual bills vary based on monthly weather patterns.¹¹⁹¹ While there may be variations, under all four scenarios, “bill burdens for households for Columbia Gas customers with income less than \$25,000 are unaffordable, and that unaffordability will increase with the rate increases proposed in this proceeding.”¹¹⁹²

¹¹⁸⁸ OCA St. 5 at 15.

¹¹⁸⁹ OCA St. 5 at 16-17, Table 2 Gap Between Q1 Income and Affordable Income.

¹¹⁹⁰ OCA St. 5 at 19.

¹¹⁹¹ *Id.*

¹¹⁹² OCA St. 5 at 20, Table 3.

In addition to concluding that Bill-to-Income Ratios are unaffordable for households with income less than \$25,000 at existing rates, and will become unaffordable for households with income between \$25,000 and \$29,999, OCA witness Colton also found “that there are significant umbers of households in the Columbia Gas service territory that live with incomes at those levels.”¹¹⁹³ Mr. Colton found that 1 in 7 households (or 13.5%) have annual income less than \$10,000. Nearly ¼ have income less than \$15,000, while more than 1/3 have income less than \$20,000.¹¹⁹⁴ OCA witness Colton concluded:

[t]he conclusions to be drawn from the data above are that Columbia Gas rates are significantly unaffordable to the lowest income customers; that the problem of unaffordability is becoming greater over time; and that the number of households affected by these unaffordable rates is very large.¹¹⁹⁵

Mr. Colton also examined the affordability for CAP-eligible households as well as for household energy bills at different levels up to 150% of the FPL.¹¹⁹⁶ Mr. Colton testified:

When customer incomes increase, bills become more affordable; however, for low-income customers at or below 100% of FPL, bills at Columbia’s existing and proposed rates are unaffordable. For customers with income in the range of 100% to 125%, bills are narrowly affordable under existing rates, but become unaffordable at the rates which Columbia proposes in this proceeding.

Columbia Gas bills are significantly unaffordable for households with income at or below 100% of FPL. For customers with income at 0-50% FPL, Bill-to-Income Ratios are more than four and a half times higher than the bill burden which the PUC has defined to be affordable. For customers with

¹¹⁹³ OCA St. 5 at 20.

¹¹⁹⁴ OCA St. 5 at 21.

¹¹⁹⁵ OCA St. 5 at 21.

¹¹⁹⁶ OCA St. 5 at 21.

incomes at 50-100% FPL, bill burdens are nearly two times higher than the affordable burden as defined by the PUC.¹¹⁹⁷

According to Columbia, it had approximately 91,849 estimated low-income customers in 2022, 91,415 estimated low-income customers in 2023, and 91,881 estimated low-income customers in 2024.¹¹⁹⁸ OCA witness Colton noted that the focus is often on the annual bills and annual burdens, but an annual basis can be deceptive. Even if annual bills represent an affordable percentage of income, the seasonal variations in Columbia's bills can present an unaffordable payment obligation in any given month.¹¹⁹⁹

CAP alone does not protect low-income customers. The design of the PIP may largely protect CAP participants from the harms of increasing rates, the CAP is only helpful to those customers who participate in the CAP PIP component. OCA witness Colton testified:

[t]he data, however, shows that the Company serves a relatively small proportion of its low-income customer base through the Company's CAP. My observation here is limited to the fact that even given the Company's CAP, there is a significant low-income customer population that is not participating in CAP and that will be adversely affected by the Company's proposed rate increase.¹²⁰⁰

According to Columbia, the Company has identified 69,708 Confirmed Low-Income customers on its system.¹²⁰¹ Of those customers, only 20,883 are CAP participants, or in other words, there are 48,825 Confirmed Low-Income customers who do not

¹¹⁹⁷ OCA St. 5 at 22, Table 4.

¹¹⁹⁸ OCA St. 5 at 23.

¹¹⁹⁹ OCA St. 5 at 23.

¹²⁰⁰ OCA St. 5 at 24.

¹²⁰¹ OCA St. 5 at 25.

participate in CAP.¹²⁰² The problem is compounded because these are only the Confirmed Low-Income customers, not the number of customers that the BCS report estimates are in Columbia's service territory. As OCA witness Colton testified:

[w]hile Columbia has confirmed the low-income status of 76% of its estimated low-income customer bases ($69,708/91,415 = 0.763$), the Company has then enrolled only 30% of that sub-population of Confirmed Low-Income customers into CAP. However, of the entire population of estimated low-income customers (91,415), Columbia has enrolled only one-in-five (22.8%) of its estimated low-income customer population into CAP ($20,883/91,415 = 0.228$)¹²⁰³

The existence of CAP, alone, cannot be used as a reason to ignore the unaffordability of Columbia's present and proposed rates on the low-income customer population. As OCA witness Colton testified:

consideration of affordability is a critical task to undertake within the structure of any utility rate case. As bills become increasingly unaffordable, the payment difficulties of those customers who face unaffordability become increasingly substantial as well.¹²⁰⁴

The Company's rate proposals in this case have a widespread impact on low-income customer affordability and vice versa. Low-income customer unaffordability impacts the operating costs such as the collection costs, working capital, uncollectibles that are then normalized and passed on through the next rate case.¹²⁰⁵ The affordability issues are compounded by the Company's proposals to increase the customer charge, the WNA, and RNA. These three elements as have been discussed further in this brief have a

¹²⁰² OCA St. 5 at 25.

¹²⁰³ OCA St. 5 at 25.

¹²⁰⁴ OCA St. 5 at 26.

¹²⁰⁵ OCA St. 5 at 26.

disproportionate impact on low-income customers who are already facing “substantial unaffordability.”¹²⁰⁶

The return established is predicated on balancing the customer and investor interest.

OCA witness Colton testified about the consumer impact:

[i]ndeed, of the consumer issues that are important drivers of the just and reasonable ROE determination, one of the most significant is the concern about affordability. If a sizable portion of customers cannot afford to pay the rates imposed by the PUC, the PUC hardly be said to have approved just and reasonable rates. Such concerns should bear directly on the determination of the fair ROE. In addition, as a utility such as Columbia adds more and more new and expensive plant, this increases costs, which may in turn put downward pressure on the just and reasonable ROE, not for financial reasons, but because of affordability concerns.

OCA witness Colton recommends that unaffordability of rates be considered in determining the appropriate revenue requirement and in structuring rates.¹²⁰⁷

D. In reaching its final determination as to a revenue requirement in this matter, the Commission should consider disproportionate impact of inflation on low-income customers.

In his Direct Testimony, Columbia witness Kempic discusses the impact of inflation but does not address the impact that inflation has on ratepayers’ ability to pay increased rates. Mr. Kempic testified that Columbia has “kept the customer’s total cost reasonable and generally in line with inflation.”¹²⁰⁸ In addition, Company witness Vassalotti adjusts future expenses based on inflation, and Company witness Rea evaluates the inflationary impacts of policy initiatives from the current Presidential administration.¹²⁰⁹

¹²⁰⁶ OCA St. 5 at 26.

¹²⁰⁷ OCA St. 5 at 27.

¹²⁰⁸ Columbia St. 1 at 8.

¹²⁰⁹ Columbia St. 4 at 34, 38-41; Columbia St. 8 at 68.

The focus of the Company witnesses are on the impact of inflation on the utility, but not on ratepayers and how inflation can impact the affordability for ratepayers. OCA witness Colton testified:

[t]he testimony of Columbia's witnesses do not present a complete story about the stress which inflation has placed on utility ratepayers, especially low-income customers. Inflation is disproportionately affecting lower-income households. The higher ROE sought by Columbia in this proceeding, which would have the impact of driving up rates, will exacerbate this problem. Given the PUC's obligation to balance the interests of investors and ratepayers in setting a reasonable ROE, the PUC should consider the greater adverse impacts that inflation has imposed on low-income ratepayers when setting rates.¹²¹⁰

OCA witness Colton also examined the research that's been completed regarding disproportionate impact of inflation on low-income households. He testified:

Research by the U.S. Department of Labor's Bureau of Labor Statistics (BLS) reports that "consumers with different incomes experience inflation quite differently." According to this research, the lowest earning households spend a disproportionately higher share of their household budget on household necessities such as rent, food, and medical care... While low-income households pay more of their budgeted income for this basket of essential goods, it is also important to note that the BLS researchers found that, "prices for motor fuel, medical care, fuel and utilities, and shelter rose faster than the overall average..." Thus, [b]ecause the lowest income households dedicate more of their spending on these categories," the BLS researchers found, "their overall inflation rates grew faster than highest income households."¹²¹¹

Similarly, OCA Colton testified that "researchers at the Federal Reserve Bank of Dallas found that "stress" being placed on households by high inflation is much greater for

¹²¹⁰ OCA St. 5 at 28.

¹²¹¹ OCA St. 5 at 30.

low-income households and low-income households have less resources and fewer options to mitigate the impact of utilities.”¹²¹²

Columbia’s portrayal of the issue of inflation only tells part of the story and places the claim of stress solely on the utility stakeholders.¹²¹³ What has not been considered is that it also places a stress on utility ratepayers, particularly lower income ratepayers.¹²¹⁴

OCA witness Colton testified:

[g]iven that inflation is disproportionately affecting lower-income households, the Commission must consider the fact that the higher ROE sought by Columbia in this proceeding will only exacerbate the problem by unnecessarily driving up rates. The PUC is obligated to balance the interests of investors and ratepayers in setting a reasonable ROE. In conducting this balance, the PUC should consider the greater adverse impacts that inflation has imposed on low-income ratepayers when setting rates.¹²¹⁵

The OCA submits that the Commission should consider as a part of setting rates the impact that inflation has had on low-income households’ ability to afford utility services, and particularly with respect to the recommendations for modifications to the programs to address these issues.

E. The Commission should consider the impact of setting a revenue requirement on moderate income ALICE households.

Low-income households are not the only customers that are impacted by the proposed rate increase and the affordability of existing rates. OCA witness Colton also examined the ability-to-pay for more moderate income households using the ALICE

¹²¹² *Id.*

¹²¹³ OCA St. 5 at 31.

¹²¹⁴ *Id.*

¹²¹⁵ OCA St. 5 at 31.

Household.¹²¹⁶ OCA witness Colton examined the dollars that an ALICE household would need in order to be self-sufficient for the counties throughout the Columbia service territory.¹²¹⁷ OCA witness Colton testified:

ALICE research reports that “a key contributor to the number of ALICE households in Pennsylvania is the fundamental mismatch between the cost of living and what jobs pay.” Common occupations throughout Pennsylvania provide insufficient wages to allow a household to cover the ALICE Survival Budget.¹²¹⁸

OCA witness Colton concluded:

[t]he ALICE data presented above provides two important insights into affordability of Columbia Gas natural gas bills. First, the data demonstrates that there is a significant population living with incomes greater than the Federal Poverty Level, but less than that which is needed to meet basic living expenses. Second, the data demonstrates that the affordability of Columbia Gas bills could well depend in substantial part on the cost-of-living in different parts of the Columbia Gas service territory.¹²¹⁹

While the focus most often is on low-income individuals, moderate income individuals also struggle with affordability.

The public input hearing testimony highlights several of these individuals and the impact of unaffordable rates on their lives. OCA witness Colton testified:

The testimony of several PIH witnesses extended my discussion by relating how the data and statistics I present are reflected in the real lived experience of Columbia Gas customers. This testimony makes clear that there are real people, facing real difficulties, which lie behind the statistics that I discuss. Based on the information and PIH testimony I discuss above, I conclude that the unaffordability problems I identified in my quantitative discussion above

¹²¹⁶ OCA St. 5 at 32. (“ALICE” is the acronym used to describe Asset-Limited, Income-Constrained, Employed (“ALICE”) households with income above the Federal Poverty Level but below the cost of basics included in the ALICE Household Survival Budget.”)

¹²¹⁷ OCA St. 5 at 34.

¹²¹⁸ OCA St. 5 at 36.

¹²¹⁹ OCA St. 5 at 41.

are experienced in the Columbia Gas service territory. The problems I identified are not abstract issues embedded in the statistics I present. They are instead real problems generating real consequences to real people. Moreover, I conclude that the additional measures I recommend that Columbia Gas can and should be undertaking should be adopted. I finally conclude that the directives which the Commission has previously included in prior orders should be continued.¹²²⁰

F. The Cost-of-Living in Columbia’s service territory can impact affordability for ratepayers.

OCA witness Colton also examines the cost-of-living and how it impacts affordability for Columbia ratepayers in its service territory.¹²²¹ OCA witness Colton testified:

Throughout the Columbia Gas service territory, there are regions that have a significantly higher cost-of-living. The fact that the cost-of-living can vary dramatically even within a single utility service territory is important in assessing a utility’s affordability. If income does not vary sufficiently to cover the increased cost-of-living, customers living in those high cost areas may face affordability problems not otherwise faced by other customers with equal bills and equal incomes. In other words, the same “energy burden” caused by utility bills may have different impacts on real life affordability when other necessities require a greater share of income.¹²²²

OCA witness Colton looks at the overall ability for the customer to be self-sufficient.¹²²³ The Self-Sufficiency Standard measures how much income a family of a certain composition in a given place needs to adequately meet their basic needs—without public or private assistance. The Self-Sufficiency Standard derives the cost-of-living by

¹²²⁰ OCA St. 5 at 119.

¹²²¹ OCA St. 5 at 41-46.

¹²²² OCA St. 5 at 41-42.

¹²²³ OCA St. 5 at 42.

combining data for housing, childcare, food, transportation, health care, taxes and “miscellaneous.”¹²²⁴

From this evaluation of the Self-Sufficiency standard in the 26 counties comprising Columbia’s service territory,¹²²⁵ OCA witness Colton was able to conclude that Columbia Gas bills will be unaffordable for those households who have incomes substantially exceeding the FPL.¹²²⁶ He also determined that there is a clear geographic scope to inability-to-pay in the Columbia Gas service territory based on the widely varying cost-of-living experienced by Columbia Gas customers.¹²²⁷

Second, there is often a tendency to assume that areas that have a higher cost-of-living also have higher incomes to offset those costs, thus leaving households in relatively similar situations.¹²²⁸ However, that is not an accurate assumption. OCA witness Colton testified:

[t]he data presented above, however, demonstrates that that assumption is not true, at least for the Columbia Gas service territory. In reality, high cost-of-living areas frequently, if not generally, are not matched with higher incomes. High cost-of-living areas demonstrate identifiable affordability problems when considering natural gas bills.¹²²⁹

Finally, OCA witness Colton draws a broader conclusion that in assessing affordability, cost-of-living should be taken in account. In particular, income deficits at

¹²²⁴ OCA St. 5 at 42.

¹²²⁵ See OCA witness Colton’s detailed analysis of the Self-Sufficiency Standard in Columbia’s service territory on pages 42-45 of OCA St. 5.

¹²²⁶ OCA St. 5 at 46.

¹²²⁷ *Id.*

¹²²⁸ OCA St. 5 at 46.

¹²²⁹ OCA St. 5 at 46.

particular levels of income may vary greatly by county, and the capacity of the household to absorb Columbia Gas bills is less if that household has an income deficit of \$25,000 or more relative to the Self-Sufficiency Standard. Mr. Colton testified “an examination of affordability based on averages, or an assertion that a certain level of bill is affordable without taking the cost-of-living into account, entirely masks the economic realities in Pennsylvania.”¹²³⁰

G. Recommendations to Address Low-Income Unaffordability

1. Introduction

In the discussion *supra*, Mr. Colton identifies the affordability problems for low-income and moderate income ratepayers created by Columbia’s current and proposed rates, and how it impacts the ability to be self-sufficient. In recognition of the impact of the above discussed impacts on affordability, Columbia should implement several changes. Columbia should implement changes to improve its identification of low-income customers. Columbia should also take more effective actions to use the universal service program to prevent disconnection of service for nonpayment to Confirmed Low-Income customers. Columbia’s proposed arrearage forgiveness pilot program should be approved. The OCA also recommends that the Company’s proposal to recover additional costs through the Rider USP be denied.

¹²³⁰ OCA St. 5 at 46.

2. Columbia should implement changes to improve its identification of low-income customers.

OCA witness Colton examined whether Columbia could benefit from changes to the process of extending service to new customers. Mr. Colton recommended that Columbia screen customers, at the time they apply for service, to determine whether these new customers might be identified as “Confirmed Low-Income” customers as well as whether these customers should be enrolled in the Company’s CAP.¹²³¹ He recommended that the Company develop a script for screening new customers for low-income status in consultation with the Company’s Universal Services Advisory Committee (USAC).

Mr. Colton explained the reason for his recommendation. He testified:

[t]he outreach that Columbia provides for its Universal Service programs today is largely provided in a reactive fashion. When a customer develops arrears and contacts the Company to arrange a deferred payment arrangement, for example, the Company seeks to educate the customer about the availability of CAP. When a customer receives a notice of the pending disconnection of service for nonpayment, the Company seeks to educate the customer about the availability of CAP. When a customer has had service disconnected and remains disconnected at the beginning of the cold weather season (and thus subject to the Cold Weather Survey), the Company seeks to educate the customer about the availability of CAP.¹²³²

The problem with this approach is that providing outreach at a time of crisis means that the customer may be less inclined to take action that may provide speculative benefits in the future and is more inclined to make a decision that is limited to resolving the immediate crisis, such as the disconnection.¹²³³

¹²³¹ OCA St. 5 at 65.

¹²³² OCA St. 5 at 65=66.

¹²³³ OCA St. 5 at 66.

OCA witness Colton examined the circumstances of Confirmed Low-Income customers who are facing the disconnection of service over the most recent 24 months.¹²³⁴

He found the following observations from the data:

- Except for the late winter months when no nonpayment disconnections occur, there are generally more accounts subject to nonpayment disconnections than there are accounts that enter into deferred payment arrangements. Over the 24 month period, excluding the winter months with no shutoffs, Columbia disconnected service to 12,254 Confirmed Low-Income customers, while entering into only 10,894 payment arrangements in those same months.
- Confirmed Low-Income customers are deeply in arrears at the time of disconnection. The average arrears at the time of disconnection ranged from a low of \$757 to a high of \$1,579.
- In eight of the 24 months studied, the number of Confirmed Low-Income customers defaulting on payment arrangements exceeded the number entering into a new arrangement. Over the 24 month period, while there were 18,215 new payment arrangements, there were 9,159 defaulted arrangements.

Moreover, less than half of Columbia's Confirmed Low-Income customers have their service reconnected.¹²³⁵

The Company has not implemented sufficient procedures to determine whether a low-income customer is being appropriately assessed a cash security deposit when the customer applies for service. OCA witness Colton testified:

Columbia concedes that it has no survey or any other study examining the demographic characteristics of the Company's disconnections for nonpayment, payment-troubled customers, customers with and without cash security deposits, or either the incidence or level of arrears. Nonetheless, the time at which the Company might gain insights into this is at the time of service application. It is at that point when the Company seeks information

¹²³⁴ OCA St. 5 at 66.

¹²³⁵ OCA St. 5 at 68.

allowing it to determine whether an applicant is “creditworthy” for purposes of requesting a cash security deposit from that applicant. In Columbia’s data filed pursuant to Section 56.231, the Company reported that it requested cash security deposits from 7,452 applicants in 2024, 6,789 applicants in 2023, and 7,027 applicants in 2022. Indeed, Columbia imposed cash security deposits on more than 1,800 applicants simply in the first three months of 2025.¹²³⁶

The OCA recommends that Columbia initiate a screening process at the time a household first applies to receive service from Columbia to determine whether the applicant: (a) should be classified as a Confirmed Low-Income customer; and (b) should be referred to the CAP application process. This screen process presents an opportunity for Columbia to leverage its speech analytics pilot program to determine if the new applicants for service might qualify for the Company’s low-income program.¹²³⁷ If the Company has sufficiently reliable information to form a reasonable belief that an applicant is not creditworthy for purposes of imposing a cash security deposit, it should also have, or be able to obtain, derive or develop, sufficient information to form a reasonable belief that the applicant is low-income or is likely to be qualified for CAP.¹²³⁸

In the Rebuttal Testimony of Company witness Davis, she opposes the OCA’s recommendation to screen applicants for whether they wish to apply for CAP and whether there is a reasonable basis to believe that such applicants may qualify for the program.¹²³⁹ Ms. Davis erroneously turns that recommendation into “requiring financial information”

¹²³⁶ OCA St. 5 at 68.

¹²³⁷ OCA St. 5 at 68-69.

¹²³⁸ OCA St. 5 at 69.

¹²³⁹ Columbia St. 16-R at 4.

and that the screening “may be perceived as intrusive, potentially leading to a negative first impression and diminishing customer satisfaction.”¹²⁴⁰

As OCA witness Colton concludes, Ms. Davis’s assertions imply that the Company does not inquire into the potential low-income status of applicants when determining whether a customer must pay a security deposit in the absence of Mr. Colton’s recommendation. Ms. Davis’s implication of the Company’s actions is inconsistent with Pennsylvania’s regulations.¹²⁴¹ Pennsylvania regulations provide that income eligible applicants – not customers but applicants – are exempt from being required to post cash security deposits.¹²⁴² Section 56.32(e) provides in relevant part:

...a public utility may not require a cash deposit from an applicant who is, based upon household income, confirmed to be eligible for a customer assistance program. An applicant is confirmed to be eligible for a customer assistance program by the public utility if the applicant provides income documents or other information attesting to his or her eligibility for state benefits based on household income eligibility requirements that are consistent with those of the public utility’s customer assistance program.¹²⁴³

Under the regulations, Columbia should already be taking the steps to determine financial eligibility for a security deposit, and OCA’s recommendation is just to utilize that provided information in order to determine eligibility for CAP. As OCA witness Colton testified:

It would not be possible for Columbia Gas to comply with this statutory mandate without inquiring into the income of the applicant. By definition, if the applicant provides sufficient income documentation to qualify for the exemption from a cash deposit, that applicant would have provided sufficient

¹²⁴⁰ *Id.*

¹²⁴¹ 52 Pa. Code § 56.32(e).

¹²⁴² 52 Pa. Code § 56.32(e).

¹²⁴³ 52 Pa. Code § 56.32(e).

income documentation to inform Columbia Gas that further effort should be made to determine if the applicant qualifies for CAP.¹²⁴⁴

For the reasons set forth above, the OCA recommends that Columbia initiate a screening process at the time a household first applies to receive service from Columbia to determine whether the applicant: (a) should be classified as a Confirmed Low-Income customer; and (b) should be referred to the CAP application process.

3. Columbia should take more effective actions to use the universal service program to prevent disconnection of service for nonpayment to Confirmed Low-Income customers.

OCA witness Colton recommended that the Company take actions to more effectively use the universal service program to prevent the disconnection of service for nonpayment by Confirmed Low-Income customers.¹²⁴⁵ OCA witness Colton testified:

[t]here are several reasons why the disconnection of service should be considered in particular...the disconnection of service has rate implications to all customers. Minimizing disconnections would also minimize these adverse rate impacts. Second, as BCS notes in its most recent annual report on universal service programs and collections performance that “Termination of public utility service is the most serious consequence of customer nonpayment and is viewed as a last resort when customers fail to meet their payment obligations.” It is thus appropriate to assess whether service terminations are, in fact, being used by Columbia as a “last resort.” Third, as BCS states: “Universal Service is a collective name applied to the policies, protections and services that help low-income customers maintain electric and natural gas service. . .” (emphasis added). Given that “universal service” is intended to “help low-income customers maintain electric. . .service,” it is appropriate to assess whether that objective is being achieved.¹²⁴⁶

¹²⁴⁴ OCA St. 5SR at 16.

¹²⁴⁵ OCA St. 5 at 69.

¹²⁴⁶ OCA St. 5 at 70(footnotes omitted) (emphasis in original).

OCA witness Colton identified concerns that the data demonstrates that the Company's universal service program is not being effectively used to help low-income customers to maintain gas service. In particular, Mr. Colton cited to the substantial number of Confirmed Low-Income customers that Columbia is disconnecting, and that the average arrears for these customers remains substantial as well.¹²⁴⁷ In addition, half of the Confirmed Low-Income customers disconnected are not being reconnected.¹²⁴⁸ As Mr. Colton described:

to assume that Columbia has effectively communicated the possibility of enrolling in CAP, and making pre-program arrears subject to forgiveness, to Confirmed Low-Income customers, one would need to assume that more than 12,250 Confirmed Low-Income customers...would choose to have their service disconnected rather than to enroll in the Company's CAP. One would further need to assume that these 12,254 customers would choose to pay all or part of their arrears in order to reconnect their service, and to retain those pre-disconnection arrears on their accounts to be paid in the future rather than subjecting those arrears to forgiveness.¹²⁴⁹

OCA witness Colton concluded that the data demonstrates that Columbia's current procedures to enroll Confirmed Low-Income customers, customers that Columbia knows are low-income, are not effectively working to help customers to enroll in CAP and to stay in CAP to retain natural gas service consistent with the Natural Gas Choice and Competition Act.¹²⁵⁰

In order to address these concerns, Mr. Colton recommends an extension of the pilots set forth in the last Columbia rate case settlement. Mr. Colton testified:

¹²⁴⁷ OCA St. 5 at 70.

¹²⁴⁸ *Id.*

¹²⁴⁹ OCA St. 5 at 71.

¹²⁵⁰ OCA St. 5 at 71-72.

In its 2024 Rate Settlement, the Company agreed to engage with its USAC to develop a series of pilot projects to address outreach to CAP Confirmed Low-Income customers (hereafter Settlement Pilots). While that Settlement provided for reporting by the Company to its USAC for a period of three years or until the Company's next base rate case (which would be this proceeding), whichever is longer, that reporting agreement was limited to the reporting on the number of customers for which cash security deposits were waived.¹²⁵¹

Mr. Colton recommends that (1) each of the pilots be extended for an additional year beyond that agreed to in the Settlement and that (2) that the reporting agreed to with respect to the waiver of deposits be extended in scope and time to each of the Settlement pilots.

The Settlement provisions that OCA witness Colton recommends be extended include: (1) the speech analytics pilot (agreed to in the last base rate proceeding and incorporated into this filing in Columbia witness Davis's testimony);¹²⁵² (2) plain language notice of the right to enter into CAP and the arrearage forgiveness benefits of CAP for confirmed low-income customers with at least \$100 in arrears; (3) plain language notice of the right to enroll in CAP when a security deposit is refunded pursuant 66 Pa. C.S. § 1404 (a.1) and 52 Pa. Code § 56.32(e); (4) plain language notice to customers at or below 150% of the FPL when negotiating a payment arrangement; (5) plain language notice to customers who have had service disconnected for nonpayment and remain disconnected at the time of the Cold Weather Survey.¹²⁵³ The Settlement provides that Columbia will report

¹²⁵¹ OCA St. 5 at 71, citing *Pa. PUC v. Columbia Gas*, Docket No. R-2024-3046519, Settlement at ¶¶ 38-46 (Aug. 28, 2024).

¹²⁵² OCA St. 5 at 73-74.

¹²⁵³ OCA St. 5 at 75; *Pa. PUC v. Columbia Gas*, Docket No. R-2024-3046519, Settlement at ¶¶ 38-46 (Aug. 28, 2024).

for at least three years, or until the final decision in the next rate case, whichever is longer, the number of customers with waived or refunded security deposits.¹²⁵⁴

OCA witness Colton acknowledged in his Direct Testimony the efforts that the Company took to implement the provisions of the Settlement and their work with the USAC to implement the recommendations.¹²⁵⁵ However, Mr. Colton identified a continuing need for outreach. Mr. Colton testified:

[a]s is evident from a review of the data and discussion presented throughout my testimony above, the need persists for the Company to continue to pursue those activities that it agreed to pursue in the 2024 Settlement. In addition, while the 2024 Settlement provided that these activities would be pursued on a “pilot” basis, with the exception of reporting on waived or refunded security deposits, there was no provision included in the 2024 Settlement as to any data reporting by which the effectiveness of the pilots could be assessed, or any time constraints on the length of time the pilot was to operate.¹²⁵⁶

The Company should take the next step in implementing the pilots in the Settlement in order to measure and publish the outcomes of those efforts. OCA witness Colton recommends that the Company:

(1) reaffirm its continuing commitment to the pursuit of these pilots; (2) deliver at each biannual meeting of the Company’s USAC a report on the implementation and results of the pilots; (3) continue its collaborative approach regarding the operation of the pilots from USAC members; and (4) to include, as part of its filing in the next base rate case, a report on the activities and results of the pilots. The pilots should be extended beyond the three years initially agreed to. Given that the pilots represent CAP outreach, the incremental costs, if any, of the pilots should be subject to recovery through the Company’s Universal Service Rider.

¹²⁵⁴ OCA St. 5 at 75 *Pa. PUC v. Columbia Gas*, Docket No. R-2024-3046519, Settlement at ¶¶ 38-46 (Aug. 28, 2024).

¹²⁵⁵ OCA St. 5 at 75.

¹²⁵⁶ OCA St. 5 at 75.

OCA witness Colton also had an additional recommendation regarding the Company's implementation of Paragraph 43 of the 2024 Settlement. Paragraph 43 of the Settlement provided:

A Customer or Applicant that provides self-certification or other income documentation that household income is at or below 150% of the federal poverty level shall not be asked to provide a cash deposit.¹²⁵⁷

OCA witness Colton requested in discovery the script being used to handle demands for a security deposit for new customers and the option for low-income customers to avoid a security deposit.¹²⁵⁸ Mr. Colton testified:

In the Columbia Gas response, the Company provided its "deposit scripting in the self-service workflow," a copy of which response is attached to my Testimony as Exhibit RDC-2. The Company response states in relevant part:

There are a variety of factors that determine if a deposit is due when customers decide to start service via the website or mobile app. Some of those factors may include credit score from the PosID check we make to the major credit house Equifax, credit risk score, payment history, and more. If a deposit is required, the customer must agree to the deposit in order to continue self-serving. If the customer does not agree to the deposit, they cannot continue self-serving and must call a customer service representative.¹²⁵⁹

OCA witness Colton identified a concern that the Company's response and the Company's self-service workflow do not provide a reference to the fact that a low-income customer is exempt, by both statute and PUC regulation, from being required to post a cash

¹²⁵⁷ *Pa. PUC v. Columbia Gas*, Docket No. R-2024-3046519, Settlement at ¶ 43 (Aug. 28, 2024).

¹²⁵⁸ OCA St. 5 at 77.

¹²⁵⁹ OCA St. 5 at 78, Exh. RDC-2 (footnotes omitted).

security deposit.¹²⁶⁰ He testified that “[e]ven if Columbia Gas fully implemented the change in its Tariff, as agreed to in the 2024 Settlement, the availability of a low-income exemption is not being communicated to the customer.”¹²⁶¹

In order to address the concern, OCA witness Colton recommended that:

in addition to any tariff amendment which the Company has or will make to reflect the low-income exemption from cash security deposits, the Company should further be directed to, within 60 days of a final order in this proceeding, modify any policies, practices, standard operating procedures, or other internal activities so as to fully communicate in a clear and timely manner the fact of that low-income deposit exemption to new applicants.¹²⁶²

The Commission has previously held that Columbia Gas should refund deposits to income-eligible customers who had previously posted such deposits.¹²⁶³ The notice recommended here simply seeks to ensure that deposits are not collected from applicants.¹²⁶⁴ The provision of the 2024 Settlement is only effective if the Company communicates the exemption to new applicants. All modifications to the processes should be shared with the USAC.¹²⁶⁵

In Rebuttal Testimony, Columbia witness Davis responded to OCA witness Colton’s recommendations regarding the pilot projects in the 2024 Settlement. Ms. Davis appears to agree to the recommendations; however, her commitment was a bit ambiguous.

¹²⁶⁰ OCA St. 5 at 78.

¹²⁶¹ OCA St. 5 at 78.

¹²⁶² OCA St. 5 at 78.

¹²⁶³ *Columbia Gas of Pennsylvania, Inc. Universal Service and Energy Conservation Plan for 2024-2028 Submitted in Compliance with 52 Pa. Code § 62.4*, Docket No. M-2023-3039487, Order at 31 (April 2024).

¹²⁶⁴ OCA St. 5 at 78.

¹²⁶⁵ OCA St. 5 at 78-79.

Ms. Davis testified: “[t]he Company confirms that it is implementing the terms of the 2024 Settlement? at Docket No. R-2024-3046519 related to Universal Services and will continue to do so per the terms set forth therein.”¹²⁶⁶ OCA witness Colton explained the ambiguity in Columbia witness Davis’s response:

[t]he problem with that rebuttal testimony of Ms. Davis is that the “terms set forth” in the 2024 Settlement include no provision as to any data reporting by which the effectiveness of the pilots could be assessed, or any time constraints on the length of time the pilots were to operate. To that extent, stating that the Company “will continue to [implement the terms of the 2024 Settlement] per the terms set forth” in the Settlement does not capture the needs in this proceeding. Given the nature of the “pilot” project, there is a need for Columbia to report the activities and results of the pilots. My Direct Testimony recommends that such a reporting of information on the 2024 Settlement pilots should occur in the Company’s next base rate case.¹²⁶⁷

Columbia witness Davis’s Rebuttal Testimony did not specifically state any opposition to Mr. Colton’s recommendation.

Consistent with the need shown in the data presented by OCA witness Colton, the OCA recommends that the pilots identified in the 2024 Settlement be extended to work towards the deficiencies in enrolling Confirmed Low-Income customers in CAP identified by OCA witness Colton. The OCA also recommends the Company be directed within 60 days of a final Order in this proceeding to modify any policies, practices, standard operating procedures, or other internal activities so as to fully communicate in a clear and timely manner the fact of that low-income deposit exemption to new applicants

¹²⁶⁶ Columbia St. 16-R at 18.

¹²⁶⁷ OCA St. 5SR at 18.

4. Columbia's proposed arrearage forgiveness pilot should be approved.

OCA witness Colton recommended that Columbia's proposed arrearage forgiveness pilot be approved.¹²⁶⁸ Columbia proposed a two-year pilot in which the Company would provide a one-time grant to assist with the payment of outstanding arrearage balances for customers who are otherwise eligible to re-enter the Company's CAP. The Company proposes to fund the two-year CAP pilot at \$100,000 annually and the costs would be recovered through the Rider USP. Columbia estimates that a minimum of 153 customers would be assisted through the pilot.¹²⁶⁹ Under the pilot, the Company would issue a grant up to \$650 for payment of CAP arrears in order to facilitate re-entry into the CAP. Customers must meet all eligibility requirements for entry into CAP and must have a balance at or below \$650.¹²⁷⁰

The Company would evaluate the pilot program by tracking the customers that received the CAP grants and assess whether the payment rates and the duration of the participation in CAP compares to customers that re-entered CAP without the grant. Columbia's determination of success of the pilot would be shown through higher participation in CAP, improved participation rates, increased reverification rates and continued participation in CAP. A minimum of two years after completion, the Company

¹²⁶⁸ OCA St. 5 at 107-111.

¹²⁶⁹ Columbia St. 16 at 3.

¹²⁷⁰ *Id.* at 3-4.

will be required to analyze the impact to reverification rates.¹²⁷¹ OCA witness Colton also agreed with the metrics proposed.

For the reasons set forth in Ms. Davis's testimony and Mr. Colton's testimony, the OCA recommends that the pilot be approved.

5. Columbia's proposal to change the cost recovery for CARES and CAP administrative costs should be denied.

The OCA recommends that the Company not be permitted to shift recovery for the CARES and internal CAP administration (referred to by the Company as EAT Team costs) in the amount of \$220,000 from base rates to the Rider USP. The proposed costs are not appropriate for recovery in the Rider USP. Collection through the Rider USP is narrowly defined and the proposed expansion to include Call Center EAT costs expands the scope.

Through this shift from base rates to the Rider USP, Columbia witness Paloney proposed to change the manner in which certain low-income internal administrative costs be recovered. Ms. Paloney testified:

[t]he Company is proposing to modify the recovery of costs associated with CARES, specifically LIHEAP, and CAP internal administration. They are currently recovered through base rates as part of Operation & Maintenance expenses. These costs are directly related to all of Columbia's low-income assistance programs, and accordingly, these costs should be moved out of base rates and recovered through Rider USP.¹²⁷²

Company witness Davis proposed that \$220,000 in internal administrative costs be switched from base rates to the Rider USP.¹²⁷³

¹²⁷¹ Columbia St. 16 at 3.

¹²⁷² Columbia St. 9 at 18-19; Columbia St. 16 at 10-15.

¹²⁷³ Columbia St. 16 at 10-15.

OCA witness Colton reviewed the Company's proposal. Mr. Colton testified:

According to the Company, in Calendar Year 2024, Columbia Gas incurred \$65,790 in internal CAP administrative costs. In the twelve months ending March 2025, CAP administrative costs were virtually identical (\$67,027). More important than the actual costs which the Company reports, however, is the fact that the Company does not budget internal CAP administrative costs. The purpose of recovering costs through the Rider USP is to ensure that budgeted (or projected) costs can be reconciled against actual costs. However, when OCA requested Columbia Gas to provide "the specific dollar amount of administrative costs for the CAP budgeted, disaggregated by. . .the total of all administrative costs," Columbia Gas responded that "The company does not budget at the program level and is unable to provide this level of detail."

Finally, when OCA asked the Company to disaggregate its internal administrative costs by various cost categories, including "overhead," "information technology," and "contingency," and "other" (specifying what the "other" is), the Company could not provide those dollars.¹²⁷⁴

As a result of the Company's responses, OCA witness Colton determined that there is no reason that costs such as these should be collected through the Rider USP.¹²⁷⁵

The Company is seeking to recover the costs for various miscellaneous programs through its Rider USP which is not permissible. The Rider USP "is not a mechanism for Columbia Gas to use to recover costs imposed by federal and state agencies."¹²⁷⁶ The Rider USP is also not "intended to be the catch-all through which Columbia Gas is to recover the costs of miscellaneous temporary federal and/or state programs, such as COVID relief

¹²⁷⁴ OCA St. 5 at 112.

¹²⁷⁵ OCA St. 5 at 112.

¹²⁷⁶ OCA St. 5 at 114.

programs cited by Ms. Davis.”¹²⁷⁷ These programs included the Homeowners Assistance Fund and the Emergency Rental Assistance Program.¹²⁷⁸

The Company’s intent is clear from Ms. Davis’s testimony that the Company proposes to expand the categories of costs to be recovered through the Rider USP. Company witness Davis testified that part of the costs that the Company seeks to recover results not from Company programs, but rather from additional costs imposed by the federal LIHEAP program. Columbia witness Davis testified:

[t]he Company shifted the responsibilities of customer referrals to available programs to the Customer Care Center and designated the EAT as the centralized team for local and state agencies to contact for account review and coordinating grant approvals while still retaining the responsibility of processing LIHEAP and Crisis payments, refunds, and LIHEAP application mailings. As the demands of LIHEAP increased due to end of year refunds, summer supplemental payments, and reporting requirements, the Company hired two additional full-time employees.¹²⁷⁹

Company witness Kempic also asserts that the costs proposed to be switched from recovery through base rates to recovery through the Rider USP should include the costs of CARES, specifically LIHEAP and the CAP administrator.¹²⁸⁰ Without support for her assertions, Ms. Paloney testifies that “these costs are directly related to all of Columbia’s low-income assistance programs, and accordingly, these costs should be moved out of base rates and recovered through the Rider USP.”¹²⁸¹

¹²⁷⁷ OCA St. 5 at 114, citing Columbia St. 16 at 14.

¹²⁷⁸ OCA St. 5 at 114.

¹²⁷⁹ Columbia St. 16 at 13.

¹²⁸⁰ Columbia St. 1 at 25-26.

¹²⁸¹ Columbia St. 9 at 19.

In Rebuttal Testimony, Columbia witness Davis argues that the costs result directly from the administration of universal services.¹²⁸² OCA witness Colton testified that “inclusion of administrative costs in the Universal Service Rider is only appropriate when such costs might fluctuate thus posing a risk that the costs would not be fully recovered.”¹²⁸³ Columbia witness acknowledges that the “the number of employees that staff the EAT is identified and approved in the Company’s USECP.”¹²⁸⁴

Moreover, the tariff specifically limits the categories allowable for recovery of Rider USP costs. Costs are not automatically deemed to be “universal service” costs simply because they are directed towards low-income customers.¹²⁸⁵ OCA witness Colton testified:

The Columbia Gas “Rider USP” tariff, for example, appropriately notes the limitations of the Rider. The tariff provides: “The Rider USP rate shall be calculated to recover costs for the following programs: Low Income Usage Reduction Program (LIURP); Customer Assistance Program (CAP); and the WarmWise® Audits and Rebates program; and the Emergency Repair Program (ERP).” (Columbia Gas PA Tariff, Rider USP). The costs of the CARES program, for example, are not included in the Rider. No cost associated with the Company’s hardship fund are collected through the Rider. No costs of LIHEAP outreach, Crisis outreach, or the administration of the Crisis program, are included in the Rider. Costs associated with administering winter disconnection protections, the negotiation of low-income deferred payment arrangements, or the determining low-income customer exemptions from cash security deposits are not collected through the Rider USP. The Rider USP is intended to be a reconcilable rider to account for the fluctuating nature of the costs of the listed programs. Columbia Gas generally, and the rebuttal testimony of Columbia Gas witness

¹²⁸² Columbia St. 16-R at 15.

¹²⁸³ OCA St. 5SR at 16.

¹²⁸⁴ Columbia St. 16-R at 15.

¹²⁸⁵ OCA St. 5SR at 17.

Davis in particular, has not established the propriety of collecting the EAT costs through the Rider USP.¹²⁸⁶

OCA witness Colton correctly testified that these statements were inaccurate. As discussed above regarding CARES, Columbia has done very little cross-program implementation that relates to other low-income programs and CARES is not a category of costs recoverable through the Rider USP.¹²⁸⁷ The Commission has also previously held with respect to internal administrative costs of universal service programs that the utility bears the burden to prove that those costs are appropriately recovered through the reconcilable surcharge.

The OCA recommends that the Company's proposal to move \$220,000 from base rates to the Rider USP be denied.

6. Conclusion

The OCA recommends that Columbia should implement changes to improve its identification of low-income customers. Columbia should also take more effective actions to use the universal service program to prevent disconnection of service for nonpayment to Confirmed Low-Income customers. Columbia's proposed arrearage forgiveness pilot program should be approved. The OCA also recommends that the Company's proposal to recover additional costs through the Rider USP be denied.

¹²⁸⁶ OCA St. 5SR at 17.

¹²⁸⁷ OCA St. 5 at 114.

XIV. ENERGY EFFICIENCY PROGRAMS

A. Introduction

With its rate case filing, Columbia has also proposed a voluntary Phase II Three-Year Energy Efficiency Plan (Plan) that will expand upon its Phase I program offerings. OCA witness Stacy Sherwood addressed the cost-effectiveness, the proposed deemed savings assumptions, the Plan's compliance with the December 23, 2009 Secretarial Letter in Docket No. M-2009-2142851 regarding voluntary energy efficiency and conservation (EE&C) programs, and the overall reasonableness of the Plan.¹²⁸⁸

Columbia's EE&C Plan includes three energy efficiency programs designed to reduce natural gas consumption by 2.7 million Dth in the first year savings over the three-year Plan.¹²⁸⁹ Phase II continues the Residential Prescriptive (RP) and Online Audit Kit (OAK) programs from Phase I and also adds a Small Commercial program.¹²⁹⁰ The total proposed cost of the Plan is \$7,884,579 over the three plan years with annual budgets from \$2.5 million to \$2.8 million.¹²⁹¹ As OCA witness Sherwood testified:

Of the \$7.8 million projected costs for the energy efficiency programs' three-year Plan, 55% of the costs are allocated for customer incentives, which will pass through to participating customers. The remaining 45% of costs are allocated between administration (35%), marketing (5%), and inspections/evaluation (5%).

Table 1 below highlights the cost and savings breakdown by customer class, for the energy efficiency programs. Common costs are allocated between the residential and commercial rate classes based upon the percentage of total

¹²⁸⁸ OCA St. 7 at 1.

¹²⁸⁹ OCA St. 7 at 2-3.

¹²⁹⁰ OCA St. 7 at 3.

¹²⁹¹ OCA St. 7 at 3.

incentives, which the Company forecasts at 79% for residential and 21% for small commercial.¹²⁹²

Table 4 Phase II Energy Efficiency Projected First Year Energy Savings by Customer Class

Customer Class	Total Projected Savings (Dths)	Percent of Total Savings	Dths Total Spending	Percent of Total Spending
Residential	127,327	80%	\$6,178,155	78%
Small Commercial	32,598	20%	\$1,706,424	22%
Total	159,925	100%	\$7,884,579	100%

OCA witness Sherwood also testified regarding the proposed cost recovery for the Plan’s development, administrative, and program costs. She testified:

The Company plans to allocate the costs among residential customers on Rate Schedules Residential Sales Service (“RSS”) and Residential Distribution Service (“RDS”), non-residential customers served on Rate Schedules Small General Sales Service (“SGSS”), Small Commercial Distribution (“SCD”), and Small General Distribution Service (“SGDS”). There is no apparent subsidization between customer classes, as the Company recovers costs in proportion to the costs expended by each customer class.

The costs would be recovered over a three-year period, with a subsequent fourth year allowing for the true-up of any under- or over-collections.¹²⁹³

Ms. Sherwood did not raise any concerns with the proposed cost recovery proposal.¹²⁹⁴

Ms. Sherwood determined that the Company had met the basic elements for the requirements of a voluntary EE&C Plan pursuant to the Secretarial Letter dated December

¹²⁹² OCA St. 7 at 3.

¹²⁹³ OCA St. 7 at 7-8.

¹²⁹⁴ OCA St. 7 at 8.

23, 2009 in Docket No. M-2009-2142851.¹²⁹⁵ Overall, Ms. Sherwood stated that she believed that the program was reasonable, beneficial, and cost-effective for consumers. OCA St. 7 at 6. After comparing the Plan to Columbia Gas' historical EE&C achievements, the forecasted level of costs and savings seems reasonable. OCA St. 7 at 6. She found that the overall portfolio was also cost-effective. Ms. Sherwood testified:

The overall portfolio, as well as individual sector portfolios, are projected to be cost-effective. A total resource cost ("TRC") ratio above 1.0 indicates that the program provides benefits that exceed the costs invested in the program, indicating that ratepayers, including non-participants, receive a return on the investment in energy efficiency. As presented by the Company, the Plan is projected to be cost-effective, with a TRC of 2.49 over the three-year period. The Plan's energy efficiency programs are also projected to be cost-effective individually, with a TRC of 2.32 for the RP Program, a TRC of 5.78 for the OAK Program, and a TRC of 1.8 for the SC Program. residential portfolio and a TRC of 1.77 for the commercial and industrial portfolio. The Combined Heat and Power program is projected to have a TRC of 1.38.¹²⁹⁶

OCA witness Sherwood recommended the following changes to the proposed Plan:

(1) in future filings, the Company should use the most recent available market information to support development of the portfolio; (2) as part of the Company's rebuttal, the Company should ensure the model utilizes the most current information provided in the Commission's Phase V orders and provide updated information to support the proposed Plan¹²⁹⁷; (3) the RP should only offer WiFi programmable thermostats that are compatible with the Electric Distribution Companies' (EDC) WiFi programmable thermostat demand

¹²⁹⁵ OCA St. 7 at 5.

¹²⁹⁶ OCA St. 7 at 6-7.

¹²⁹⁷ The Phase V Commission Orders referenced include the 2026 TRC Test Final Order in Docket No. M-2024-3048998, the 2026 Technical Reference Manual Final Order in Docket No. M-2023-3044491, and as guidance Phase V Tentative Implementation Order in Docket No. M-2025-3052826,

response programs if ones are offered; (4) to encourage participation of qualified low-income customers in the RP, the Company should cover up to 80 or 90% of weatherization costs; (5) weatherizing a home can ensure proper sizing of heating units. The Company should offer a bonus incentive for comprehensive projects completed through the RP for customers which install a new heating system with air sealing and insulation; (6) the Commission should require the Company to file within the docket all evaluation, measurement, and verification reports completed on the programs for transparency; (7) Columbia should retain an independent third-party evaluation contractor to perform its evaluations; and (8) when appropriate, the Company should coordinate with the EDC programs.¹²⁹⁸

Act 129 EE&C plans must measure and verify savings based upon the TRM and TRC test as approved by the Commission.¹²⁹⁹ While Columbia's voluntary EE&C Plan is exempt from the requirements, the Company indicates as part of its Plan filing that it will conduct impact and process evaluations of its programs, with the evaluation timing dependent upon the program.¹³⁰⁰ OCA witness Sherwood testified, "[f]ormal evaluation of the programs, to verify savings, installation rates, and free ridership is important, particularly as Act 129 electric distribution companies do not offer gas measures."¹³⁰¹ OCA

¹²⁹⁸ OCA St. 7 at 4-5.

¹²⁹⁹ The December 23, 2009 Secretarial Letter in Docket No. M-2009-2142851, p 1-2.

¹³⁰⁰ OCA St. 7 at 7.

¹³⁰¹ OCA St. 7 at 7.

witness Sherwood recommended that the Company publicly file its evaluation reports, in a timely manner, at the docket.¹³⁰²

I&E and CAUSE-PA also addressed Columbia's energy efficiency proposals in their respective testimonies. The OCA did not address their respective recommendations in its testimonies.

B. In its Rebuttal Testimony, the Company adopted, in full or in part, several of OCA witness Sherwood's recommendations.

As discussed below, the Company agreed to adopt, in full or in part, some of Ms. Sherwood's recommendation including: (1) to use the most recent available market information to support the development of its portfolio in future filings; (2) to file within this docket all EM&V reports completed on the programs; and (3) to coordinate with the EDC programs.¹³⁰³ The OCA discusses below those adopted recommendations and the additional modifications and clarifications that OCA witness Sherwood recommend still be included.

1. Market Data

In order to develop the forecasted levels of participation, the Company relied upon its historical performance from Phase I, market data from the 2018 Act 129 Residential Baseline Survey, market data from the 2018 Act 129 Residential Baseline Survey, the 2009 Residential Energy Consumption Survey, Columbia Gas Rate Division Data Request on Residential customer forecasts, and climate data.¹³⁰⁴ OCA witness Sherwood expressed

¹³⁰² OCA St. 7 at 7.

¹³⁰³ OCA St. 7SR at 3.

¹³⁰⁴ OCA St. 7 at 8.

concerns about the market data used to perform its forecasts because the data was outdated and more recent data is and was available prior to the filing of the rate case.¹³⁰⁵ She cited to the 2023 Act 129 Residential Baseline Study that was released on March 21, 2024 which updated information used to inform heating and water heating usage by fuel type and by EDC and the 2009 Residential Energy Consumption Survey data was updated twice, in 2015 and again in 2020.¹³⁰⁶ She also identified that the climate data used by Columbia is based upon the 2021 Technical Resource Manual (TRM). Since that time, the Appendix A was updated on May 25, 2024 to support the 2026 TRM Final Order.¹³⁰⁷ OCA witness Sherwood testified that the Company should have updated the climate data assumptions and the relevant data that was updated in 2024 for Act 129 Phase V, such as the avoided costs related to electricity and water.¹³⁰⁸

Ms. Sherwood testified that “it is unclear to what extent outdated information was used throughout the assumptions supporting the proposed Plan.” She cited an example of whether the avoided cost calculations reflected the updated assumptions provided by Phase V orders on the TRM and TRC. Ms. Sherwood testified “an example of this is that the avoided cost for water which assumes \$0.0132 per gallon in 2021 dollars, but the Phase V TRC Final Order indicates that the assumption should be \$0.0142 per gallon in 2026

¹³⁰⁵ OCA St. 7 at 9.

¹³⁰⁶ OCA St. 7 at 9.

¹³⁰⁷ 2026 Technical Reference Manual 2026 TRM Appendix A adopted September 12, 2024 in Docket No. M-2023-304491 <https://www.puc.pa.gov/pcdocs/1848572.xlsx>.

¹³⁰⁸ OCA St. 7 at 9.

dollars.”¹³⁰⁹ As she explained, in that example, the avoided cost is higher, which would improve the cost-effectiveness of the Plan, but updates like this could go either way, either positively or negatively. OCA witness Sherwood recommended that if the Company files any future energy efficiency plans with the Commission that it should use the most recent data to support the Plan Development, and that as part of the Rebuttal, the Company should ensure that the model utilizes the most current information provided in the Phase V Orders and provide updated information to support the proposed Plan.¹³¹⁰

In the Rebuttal, Company Nunley stated that the Company would adopt the OCA’s recommendation to update its compliance filing to incorporate the most recent market information and will do so in future filings.¹³¹¹ Mr. Nunley indicated that the Phase V Commission Order was released on June 18, 2025. In Surrebuttal Testimony, OCA witness Sherwood agreed that the Order should be considered in the Company’s filing in addition to the Commission’s Orders related to the Phase V Technical Resource Manual and Total Resource Cost test that were released prior to the Company’s filing in this docket.¹³¹² She testified that “if as part of that update program modifications are needed, the Company should be required to file those with the Commission.”¹³¹³

¹³⁰⁹ OCA St. 7 at 9, citing *2026 TRC Test Final Order* adopted November 7, 2024 in Docket No. M-2024-3048998, page 59.

¹³¹⁰ OCA St. 7 at 10.

¹³¹¹ Columbia St. 13-R at 11.

¹³¹² OCA St. 7SR at 3.

¹³¹³ *Id.*

2. Residential Prescriptive Program

The Residential Prescriptive Program (RP Program) provides opportunities for residential customers to install efficient gas space and water heating equipment in their homes.¹³¹⁴ The program offers Energy Star furnaces, boilers, tankless water heaters, fireplace inserts, and gas heat pumps and insulation, air sealing, and WiFi thermostats. As OCA witness Sherwood testified, the insulation, air sealing, and WiFi thermostats are available through the EDCs' current programs, and based upon the Act 129 Phase V Tentative Order, there is also now the potential for the EDCs to offer demand response programs which may utilize smart thermostats. OCA witness Sherwood testified that there is the potential for confusion by customers and vendors about the measure offerings.

OCA witness Sherwood recommended that the Company should connect with the EDCs with overlapping service territories to consider potential cost sharing options, leveraging of rebates, and messaging.¹³¹⁵ Ms. Sherwood testified:

if an EDC is approved to offer a demand response opportunity that leverages smart thermostats, then Columbia Gas should limit the thermostats eligible under its program to those that can also participate in the demand response opportunity. This will leverage energy efficiency opportunities through the service territories, as well as limit the potential for a Columbia Gas funded thermostat of being uninstalled in lieu of an EDC's demand response capable thermostat, which may provide incentives over time rather than upfront. The Company should coordinate with the EDCs in which its service territory overlaps on energy efficiency offerings, including thermostats and weatherization to avoid customer and contractor confusion.¹³¹⁶

¹³¹⁴ OCA St. 7 at 10.

¹³¹⁵ OCA St. 7 at 11.

¹³¹⁶ OCA St. 7 at 11.

The Company adopted the OCA's recommendation only in part. Although the Company agreed to coordinate, if possible, with the EDCs, the Company did not accept the OCA's recommendation that the smart thermostat rebates should be limited to technology that is compatible with the EDCs.¹³¹⁷ OCA witness Sherwood testified:

[t]he Company stated that it would be counterproductive to its end goal to have customers use less natural gas as it would limit the availability of smart thermostats for customers to choose from and that it is unclear if the EDCs will offer a smart thermostat demand response program as the plans will not be filed until November 2025 for implementation in June 2026.¹³¹⁸

Under the Company's theory, there would only be a limited list of compatible thermostats, but the Company's assumptions may not prove to be accurate. OCA witness Sherwood disagreed and testified:

however, as pointed out by the Company, a list is not available as the EDCs are not required to file their plans until November 2025. The Company should reach out to the EDCs, as the Company is aware, that plans are developed and designed in advance of a regulatory filing. The Company should inquire as to whether a smart thermostat demand response program or a smart thermostat rebate will be offered by the EDCs. If so, there should be coordination between the two and offer potential for collaboration that could provide shared savings and shared costs. The Company should document its coordination efforts and collaboration with EDCs in its annual filing.¹³¹⁹

As recommended by OCA witness Sherwood, the Company should proactively reach out to the EDCs to work with them about the type of smart thermostat demand program and rebate that the EDC may be offering, and if there is a program, they should seek to coordinate the programs.

¹³¹⁷ Columbia St. 13-R at 12.

¹³¹⁸ OCA St. 7SR at 5.

¹³¹⁹ OCA St. 7SR at 5-6.

OCA witness Sherwood also testified that the weatherization of a home is extremely important and is often overlooked as it can be invisible to homeowners.¹³²⁰ Ms. Sherwood supported the Company's inclusion of air sealing and insulation as part of its measure offerings. However, she recommended that the enhanced rebate could be redesigned to address the cost barrier for low-income qualified customers. She testified:

These measures not only provide bill savings, but they can also increase comfort for the occupants. There are two opportunities for the Company to increase the adoption and installation of air sealing and insulation. First, as the Company does not offer a distinct income eligible program, the Company should consider offering an enhanced incentive to customers that qualify as low income. Specifically, the enhanced incentive should target qualified low-income customers that do not meet the usage thresholds under Columbia Gas' Low Income Usage Reduction Program ("LIURP"). The enhanced rebate could be designed to cover up to 80-90% of the insulation and air sealing costs, to reduce the cost barrier for qualified customers.¹³²¹

In Mr. Nunley's Rebuttal Testimony, Columbia claimed that the recommended modification to cover 80-90% of the weatherization costs in the RP program to qualified low-income customers to encourage participation has already been addressed.¹³²² OCA witness Sherwood did not agree with the Company that her recommendation had been addressed. She testified:

Related to increased rebates for qualified low-income customers, I agree that qualified low-income customers do have an opportunity to receive weatherization measures at a discounted price through a combination of the Company's Audit and Rebate ("A&R") Program and the Residential Prescriptive ("RP") Program. However, there is potential that with the measure offerings and limitation on rebates that a qualified low-income participant may still encounter a cost barrier if more than 10-20 percent of the cost remains. If the Company opts to not offer a rebate to cover up to 80-

¹³²⁰ OCA St. 7 at 11.

¹³²¹ OCA St. 7 at 11.

¹³²² Columbia St. 13-R at 10.

90% of the weatherization costs the combination of the two programs' rebates, the Company should track the balance that low-income customers are expected to pay and whether the customer moves forward with the project. This information will help to inform whether the rebate offerings are sufficient to garner participation from low-income customers. If it is identified that qualified income customers are pursuing the work, the Company should reevaluate the rebate offering under the RP program.¹³²³

In addition, the Company did not adopt OCA witness Sherwood's recommendation regarding bonus incentives. OCA witness Sherwood also recommended:

Second, equipment replacements often occur upon failure, which typically means that customers may not be considering the installation of weatherization measures. Adoption of weatherization measures can reduce the size of the heating equipment due to a tighter envelope. The Company should encourage the adoption of weatherization measures prior to the implementation of new heating equipment. The value of the bonus incentive should be based on the number of projected rebate opportunities and the impact to cost-effectiveness, with the rebate being a few hundred dollars.¹³²⁴

The Company did not accept Ms. Sherwood's proposal to offer a comprehensive bonus to customers that opt to install a new heating system at the same time as air sealing and insulation.¹³²⁵ In Rebuttal Testimony, Company witness Nunley argued that the rebates are designed based upon incremental cost and that they do not take into consideration the sizing.¹³²⁶ As a result, the Company argued that it will not necessarily lead to greater savings even if it could lead to greater system efficiency through proper sizing of the equipment.¹³²⁷

¹³²³ OCA St. 7SR at 3-4.

¹³²⁴ OCA St. 7 at 11-12.

¹³²⁵ OCA St. 7SR at 5; Columbia St. 13-R at 12.

¹³²⁶ Columbia St. 13-R at 12.

¹³²⁷ *Id.*

The OCA does not agree with the Company's assessment of the operational savings that could be achieved with the more comprehensive bonus proposal that Ms. Sherwood recommended. OCA witness Sherwood testified:

[w]hile the Company may establish rebate levels based upon incremental cost, there is potential for operational savings for the participants, as recognized by the Company. Outside of operational savings, this opportunity will encourage participants to implement more than one measure at the time of service rather than relying on the customer to follow up for additional services in the future. A comprehensive bonus does not need to be substantial, only enough to motivate the additional services. The Company could run a pilot to see how a comprehensive bonus impacts the program but should at a minimum evaluate the inclusion of a comprehensive bonus into its cost-effectiveness test.¹³²⁸

For the reasons set forth above, the OCA recommends that the Company should coordinate with the EDCs and only offer WiFi programmable thermostats that are compatible with the EDC demand response programs if offered. To encourage participation of qualified low-income customers in the Residential Prescription Program, the Company should cover up to 80 or 90% of weatherization costs. The Company should offer a bonus incentive for comprehensive projects completed through the Residential Prescription Program for customers which install a new heating system with air sealing and insulation.

C. An independent third-party evaluator should be hired to complete evaluations of the program.

OCA witness Sherwood testified that she had concerns regarding the Company's proposed process for evaluation of the program. Ms. Sherwood testified:

Green Energy Economics Group is the one that helped to develop the plan for Columbia Gas. Based on the Company's response to OCA-18-9, the Company provided an evaluation that was conducted by Green Energy

¹³²⁸ OCA St. 7SR at 6.

Economics Group. The TRM was compiled by Green Energy Economics Group. There appears to be a conflict of interest as the same company that develops the plan and the TRM, is also evaluating it. As of 2020, 78% of states have evaluations conducted by an independent third party that is neither the administrator nor the implementer. The Act 129 EDCs are evaluated by an independent third-party evaluator, known as the Statewide Evaluator. Columbia Gas should hire an independent third-party evaluation contractor to perform its evaluations to ensure independent judgment and confidence in the results.¹³²⁹

In its Rebuttal Testimony, Columbia claimed that the OCA's recommendation that Columbia should retain an independent third-party evaluation contractor to perform evaluations had already been addressed.¹³³⁰ The Company's response did not address the OCA's concern. Although the Company identified that Green Energy Economics Group's compensation is not tied to the performance of the energy efficiency plan, this was not the reason that OCA witness Sherwood raised the concern. OCA witness Sherwood testified that:

[w]hether performance is involved or not, there is still the potential for the planner to have a biased perspective on the program effectiveness and design. In addition, separation of the planner and evaluator roles allows for a second opinion on the programs and allows for a different perspective. While GEEG may be qualified for both roles, for them to provide both services to the same energy efficiency portfolio removes the impartial perspective that is expected from evaluation of energy efficiency programs.¹³³¹

An independent evaluator is important to ensuring the integrity of the program. Using the same evaluator as the program implementor will expose Columbia to the pitfalls

¹³²⁹ OCA St. 7 at 12-13 (footnote omitted).

¹³³⁰ Columbia St. 13-R at 10.

¹³³¹ OCA St. 7SR at 4.

identified by OCA witness Sherwood. The Act 129 programs require an independent evaluator and the same should be true for the voluntary programs.

D. Conclusion

For the reasons set forth above, the OCA recommends that the proposed Phase II EE&C Plan should be approved with the modifications recommended by OCA witness Sherwood. In addition to the recommendations adopted by the Company, the OCA recommends that the Commission adopt, in full, the following recommended additions to the energy efficiency program:

- The Residential Prescriptive Program should only offer WiFi programmable thermostats that are compatible with the Electric Distribution Companies' WiFi programmable thermostat demand response programs if ones are offered.
- To encourage participation of qualified low-income customers in the Residential Prescription Program, the Company should cover up to 80 or 90% of weatherization costs.
- Weatherizing a home can ensure proper sizing of heating units. The Company should offer a bonus incentive for comprehensive projects completed through the Residential Prescription Program for customers which install a new heating system with air sealing and insulation.
- The Commission should require the Company to file within the docket all evaluation, measurement, and verification reports completed on the programs for transparency.
- Columbia Gas should retain an independent third-party evaluation contractor to perform its evaluations.
- When appropriate, the Company should coordinate with the EDC programs.

XV. COMPETITIVE SUPPLY ISSUES

The OCA did not present evidence on competitive supply issues. The OCA is not briefing this issue but reserves the right to respond in Reply Brief if necessary.

XVI. TARIFF ISSUES (NOT ADDRESSED ABOVE)

A. Rate EDDS

The Company requests Commission authorization to implement a new tariff schedule, the Economic Development Distribution Service Rate (Rate EDDS).¹³³² Under Rate EDDS, the Company proposes to serve new large load customers “as non-jurisdictional customers, providing the opportunity for the Company to enter into individual contracts with these customers, allowing for billing rates that reflect the costs of their individual needs without the potential for these customers to be subsidized by jurisdictional customers.”¹³³³ If a non-jurisdictional customer utilized a portion of the distribution system providing service to jurisdictional customers, then that portion would be paid-for by the Rate EDDS customer and not borne solely by Columbia’s jurisdictional customers.¹³³⁴ A cost of service study would be submitted in subsequent rate cases to identify all common costs between jurisdictional and non-jurisdictional customers allocate such costs between them.¹³³⁵

The OCA recommends that the Company’s Rate EDDS be denied. Rate EDDS is, at this stage, premature. The Company “has recently received an inquiry from a potential

¹³³² OCA St. 1 at 58.

¹³³³ *Id.*

¹³³⁴ *Id.* at 60.

¹³³⁵ *Id.*

customer that may qualify for service under the proposed EDDS rate schedule” but the Company’s discussions with the prospective customer are still preliminary.¹³³⁶ While the OCA agrees that the goal of a rate class serving large load customers should be to prevent shifting the risk of recovering stranded investment to captive customers, until more information is available regarding the customers which would receive Rate EDDS service, the OCA cannot support the Company’s request for approval of the service classification.¹³³⁷

Therefore, the OCA requests that the Commission delay approval of the Rate EDDS classification until information is available on the usage characteristics of the customer to be served and how those characteristics are considered in the cost of service studies. At that time, approval of a large load tariff would no longer be premature or speculative, as in the instant proceeding. However, should the Commission determine to approve the proposed Rate EDDS, then the OCA respectfully requests that the Commission clarify the information Columbia must provide with its next rate filing to ensure that captive, retail ratepayers bear no costs associated with providing service to Rate EDDS customers.¹³³⁸

B. Eligible Customer Lists

In Rebuttal Testimony, Columbia witness Danhires recommended changes to Columbia’s Tariff in which she testified was to comply with the Commission’s March 13,

¹³³⁶ Columbia St. 9-R at 35.

¹³³⁷ OCA St. 1 at 60.

¹³³⁸ *Id.*

2025 Order at Docket No M-2010-2183412¹³³⁹ regarding the requirement that electric and natural gas utilities create Eligible Customer Lists after mandated customer communications.¹³⁴⁰ Ms. Danhires testified:

[a]t the March 13, 2025 Public Meeting, at Docket No. M-2010-2183412, the Public Utility Commission issued an Order that directed natural gas distribution companies (“NDGCs”) and electric distribution companies (“EDCs”) to maintain their Eligible Customer Lists (“ECLs”), but revised the program requirements as follows: (1) NGDCs and EDCs must solicit customers once every five years (instead of the current three-year cycle) for participation in the ECL; (2) once a customer has elected to opt-out of the ECL, this election shall remain in place unless the customer affirmatively opts back in (instead of a customer having to affirmatively opt-out with each solicitation); and (3) NGDCs and EDCs may utilize electronic methods to communicate with customers about the ECL. As a result of the March 13, 2025 Order, Columbia’s Tariff Page 227a must be updated to reflect these revisions.¹³⁴¹

The tariff provision of concern to the OCA provides that:

Privacy of Customer Information. The Company may release private Customer information to third parties, such as NGSs participating in the Company’s Choice program, only after informing each Customer via bill insert or email of its intent to release such information. The Company will notify customers of the option to limit or restrict their private information...¹³⁴²

The underscored language is the proposed change. While the OCA does not have concerns with the addition of the email language, the OCA is concerned about the scope of

¹³³⁹ *Guidelines for Eligible Customer Lists*, Docket No. M-2010-2183412, Order (March 13, 2025) (*ECL Order*).

¹³⁴⁰ Columbia St. 12-R at Suppl. No. 392 to Tariff Gas- Pa. PUC No. 9, Second Revised Page No. 227a.

¹³⁴¹ Columbia St. 12-R at 1-2.

¹³⁴² Columbia St. 12-R at Suppl. No. 392 to Tariff Gas- Pa. PUC No. 9, Second Revised Page No. 227a.

the privacy information provision included in the Company's existing tariff. OCA witness Alexander testified regarding her concerns about the tariff language:

I do not question the intent of the Commission's Order or the reforms reflected in that Order. However, I have a concern with the language Ms. Danhires [sic] in the Tariff Page 227a to comply with this Order. The current recommended Tariff in Section 4.5.4 allows Columbia to use this process of providing customer information to "third parties" as well as NGSs: "The Company may release private Customer information to third parties, such as NGSs participating in the Company's Choice program..." I do not agree with broadening the access to customer information under this program to unknown third parties. This Tariff language should be restricted to the use of this information to licensed NGSs.¹³⁴³

The OCA believes that the existing tariff language referring to "third parties" is beyond the scope of the *ECL Order*.

As noted in the *ECL Order*, the original purpose of the November 12, 2010 Order was to provide "for uniform categories of customer information to be made available to EGSs by EDCs and addressed customers' ability to restrict the inclusion of their information in the ECL."¹³⁴⁴ As discussed in the *ECL Order*, by Secretarial Letter dated March 1, 2024, the Commission "requested comments from all interested parties on the guidelines that govern the ECL, especially the use of electronic methods in communicating with customers, in lieu of written notices sent via the U.S. Postal Service."¹³⁴⁵ In Comments, several parties, including OCA and Columbia, proposed to eliminate the ECL.¹³⁴⁶ The Commission declined the recommendation.¹³⁴⁷ However, as a result of the

¹³⁴³ OCA St. 6 at 17.

¹³⁴⁴ ECL Order at 2.

¹³⁴⁵ ECL Order at 4.

¹³⁴⁶ ECL Order at 12.

¹³⁴⁷ ECL Order at 12-13.

Order, the Commission extended the refresh period for the ECL from three years to five years.¹³⁴⁸ The *ECL Order* also addresses means of communication to customers for supplier issues.¹³⁴⁹

The Commission also took the opportunity to remind the stakeholders about privacy concerns related to third parties. The *ECL Order* provided:

As for confidentiality concerns, the Commission takes this opportunity to remind all utilities and suppliers of their obligations to maintain the privacy and confidentiality of the customer information on the ECL. We point electric utilities and suppliers to 52 Pa. Code §54.8, relating to the privacy of customer information, which specifies that an “...**EDC or EGS may not release private customer information to a third party unless the customer has been notified of the intent and has been given a convenient method of notifying the entity of the customer’s desire to restrict the release of the private information.**” Further, 52 Pa. Code §54.43 relating to the standards of conduct and disclosures for licensees, requires that a licensee “...shall maintain the confidentiality of a consumer’s personal information including the name, address and telephone number, and historic payment information, and provide the right of access by the consumer to his own load and billing information.” The analogous regulations for natural gas utilities and suppliers can be found at 52 Pa. Code §62.78, relating to the privacy of customer information and 52 Pa. Code §62.114 relating to the standards of conduct and disclosure for licensees.¹³⁵⁰

Ms. Danhires testified that the purpose of the tariff changes were to be in compliance with the *ECL Order* changes. However, the OCA believes that the existing language is in conflict with the *ECL Order* and an expansion of the scope to unknown third parties that would be able to receive the ECL information. The tariff language would specifically be in conflict with the Commission’s noted concerns relating to maintaining customer privacy

¹³⁴⁸ ECL Order at 17.

¹³⁴⁹ ECL Order at 15.

¹³⁵⁰ ECL Order at 15 (emphasis added).

of the *ECL Order*. The ECL was expressly developed in order to facilitate the customer choice program, and not for the provision of customer information to unknown third parties.

Moreover, this tariff provision change should be viewed in conjunction with recent filing made by Columbia and its impact in that proceeding. The ALJs at the hearing also took judicial notice¹³⁵¹ that the Company had made a filing in Docket Nos. R-2018-2647577 and G-2025-3056022. In that docket, on June 30, 2025, Columbia filed a letter with the Commission to serve as notice of its plan to implement the practice of “on-bill” billing for Columbia customers.¹³⁵² In this letter, Columbia indicated that it is seeking Commission approval of its affiliate interest agreement with NiSource Dev. Co., whereby Columbia will provide, and be compensated for, certain billing services related to Pivotal, a non-affiliated third-party.¹³⁵³ The letter stated that under the agreement between NiSource Dev. Co. and Pivotal, Pivotal will offer warranty service plans, products, and services to Columbia’s customers and NiSource Dev. Co. will grant a nonexclusive right and license for service marks to be used to market Pivotal’s products.¹³⁵⁴ This agreement allows NiSource Dev. Co. to receive a revenue share percentage for the purchase of Pivotal’s products by Columbia’s customers.¹³⁵⁵ This letter further indicates that NiSource Corporate Services Company (NiSource Service Co.), on behalf of Columbia, will provide

¹³⁵¹ Tr. 413.

¹³⁵² *Pa. PUC v. Columbia Gas of Pa. Inc.*, Docket No. G-2025-3056022, Letter (June 30, 2025) (June 30, 2025 Letter).

¹³⁵³ *Id.*

¹³⁵⁴ *Id.*

¹³⁵⁵ *Id.*

billing services offered by Pivotal to Columbia customers in exchange for Pivotal's payment of certain fees, including annual and monthly service fees.¹³⁵⁶ The OCA has filed a Protest in the proceeding. In its Protest, the OCA identified concerns with the potential for on-bill financing with Columbia's affiliate.

The proposed tariff revision would expand the tariff under the *ECL Order* to third parties and if approved, among those third parties, may be such parties as Pivotal. The Commission should not allow information from the ECL to be disclosed to unknown third parties.

XVII. MISCELLANEOUS ISSUES

The OCA did not present evidence on miscellaneous issues. The OCA reserves the right to respond to issues raised in this section by other parties in its Reply Brief if necessary.

¹³⁵⁶ *Id.*

XVIII. CONCLUSION

In summary, Columbia has not met its burden of demonstrating the reasonableness of every element of its claims for rate base, expenses, rate of return, capital structure, revenue allocation, cost of service allocation, rate design, and alternative ratemaking. Accordingly, it is well within the discretion of the ALJ and the Commission to deny, and the ALJ and the Commission should deny, Columbia's ratemaking claims and requests in this proceeding that are challenged by the OCA and should adopt the OCA's fully substantiated recommendations related to such claims. The Commission should also adopt the OCA's recommendations relating to the improvement of Columbia's customer service quality, universal service, and energy efficiency programming as such recommendations are supported by substantial evidence of record and will ensure consumer access to adequate and reasonable utility service.

Respectfully submitted,

/s/ Christy M. Appleby
Christy M. Appleby
Senior Assistant Consumer Advocate
PA Attorney I.D. # 85824
CAappleby@paoca.org

Office of Consumer Advocate
555 Walnut Street
5th Floor, Forum Place
Harrisburg, PA 17101-1923
Phone: (717) 783-5048
Fax: (717) 783-7152

Harrison W. Breitman
Assistant Consumer Advocate
PA Attorney I.D. # 320580
HBreitman@paoca.org

Jacob Guthrie
Assistant Consumer Advocate
PA Attorney I.D. # 334367

Dated: August 26, 2025

jguthrie@paoca.org

Counsel for:
Darryl A. Lawrence
Consumer Advocate

APPENDIX A

TABLE I
Columbia Gas of Pennsylvania, Inc
INCOME SUMMARY
R-2025-3053499

	Pro Forma Present Rates (1)	OCA Company Adjustments (1)	Pro Forma OCA Present Rates	ALJ Adjustments	ALJ Pro Forma Present Rates	ALJ Revenue Increase	Total Allowable Revenues
	\$	\$	\$	\$	\$	\$	\$
Operating Revenue	919,007,834	(26,377,267)	892,630,567	0	892,630,567	0	892,630,567
Expenses:							
O & M Expense	467,930,273	(16,757,680)	451,877,552	451,877,551	903,755,103	0	903,755,103
Depreciation	154,650,832	(46,038,863)	108,816,982	0	108,816,982	0	108,816,982
Taxes, Other	4,493,642	(191,398)	4,309,435	0	4,309,435	0	4,309,435
Income Taxes:							
State	4,580,110	(7,323,374)	5,454,030	(34,536,883)	(29,082,853)	0	(29,082,853)
Federal	38,693,547	(10,298,868)	49,735,069	(89,579,633)	(39,844,564)	0	(39,844,564)
Total Expenses	670,348,404	(80,610,183)	620,193,068	327,761,035	947,954,103	0	947,954,103
Net Inc. Available for Return	248,659,430	54,232,916	272,437,499	(327,761,035)	(55,323,536)	0	(55,323,536)
Rate Base	3,839,638,127	0	3,861,622,942	0	3,861,622,942		3,861,622,942
Rate of Return Present Rates	6.48%		7.06%				7.06%
Allowable Rate of Return Proposed Rates			7.06%				
Net Income Available for Return			272,437,499				

(1) Company Main Brief

TABLE I(A)
Columbia Gas of Pennsylvania, Inc
RATE OF RETURN
R-2025-3053499

OCA	Structure	Cost	After-Tax Weighted Cost	Effective Tax Rate Complement	Pre-Tax Weighted Cost Rate
Total Cost of Debt			2.61%		2.61%
Long-term Debt	47.68%	5.22%	2.49%		2.49%
Short-term Debt	2.32%	5.00%	0.12%		0.12%
Preferred Stock	0.00%	0.00%	0.00%	0.73	0.00%
Common Equity	50.00%	8.90%	4.45%	0.73	6.09%
	<u>100.00%</u>		<u>7.06%</u>		<u>8.69%</u>
Pre-Tax Interest Coverage	3.34				
After-Tax Interest Coverage	2.71				

TABLE I(B)
Columbia Gas of Pennsylvania, Inc
REVENUE FACTOR
R-2025-3053499

100%	<u>1.00000000</u>
Less:	
Uncollectible Accounts Factor (*)	0.01346126
PUC, OCA, OSBA Assessment Factors (*)	0.00000000
Gross Receipts Tax	0.00000000
Other Tax Factors	<u>0.00000000</u>
	0.98653874
State Income Tax Rate (*)	<u>0.07490000</u>
Effective State Income Tax Rate	<u>0.07389175</u>
Factor After Local and State Taxes	0.91264699
Federal Income Tax Rate (*)	<u>0.21000000</u>
Effective Federal Income Tax Rate	<u>0.19165587</u>
Revenue Factor (100% - Effective Tax Rates)	<u><u>0.72099112</u></u>

(*) Company Main Brief

TABLE II
Columbia Gas of Pennsylvania, Inc
SUMMARY OF ADJUSTMENTS
R-2025-3053499

<u>Adjustments</u>	<u>Rate Base</u>	<u>Revenues</u>	<u>Expenses</u>	<u>Depreciation</u>	<u>Taxes-Other</u>	<u>State Income Tax</u>	<u>Federal Income Tax</u>
	\$	\$	\$	\$	\$	\$	\$
RATE BASE:	0						
CWC:							
Int. & Div. (Table IV)	(IV)B38)						
Taxes (Table V)	(V)P34)						
O & M (Table VI)	(VI)B42)						
REVENUES:		0				0	0
EXPENSES:							
Gas Costs			245,031,485			(18,352,858)	(47,602,512)
Labor Costs			37,072,052			(2,776,697)	(7,202,025)
Incentive Compensation			16,196			(1,213)	(3,146)
Pension Deferral			844,977			(63,289)	(164,155)
Other Employee Benefits			8,524,718			(638,501)	(1,656,105)
Outside Services			16,577,002			(1,241,617)	(3,220,431)
Building Rentals			734,000			(54,977)	(142,595)
Other Rents/Leases			545,640			(40,868)	(106,002)
Corp. Insurance			4,320,454			(323,602)	(839,339)
Injury & Damages			353,800			(26,500)	(68,733)
Employee Expenses			1,240,788			(92,935)	(241,049)
Co. Memberships			428,924			(32,126)	(83,328)
Utilities/Company Used Gas			2,104,577			(157,633)	(408,858)
Advertising			402,724			(30,164)	(78,238)
Fleet/Other Clearing			7,518,942			(563,169)	(1,460,712)
Materials & Supplies			5,522,212			(413,614)	(1,072,806)
Other O&M			173,561			(13,000)	(33,718)
PUC/OCA/OSBA Fees			3,299,312			(247,118)	(640,961)
NCSC-Shared Services			71,522,807			(5,357,058)	(13,894,807)
DEI Costs			(130,450)			9,771	25,343
Rate Case Expenses			1,138,793			(85,296)	(221,234)
Uncollectible Accounts			9,487,724			(710,631)	(1,843,190)
Uncollectible Accounts - Unbundled			1,187,650			(88,955)	(230,726)
COVID 19 Amortization			708,091			(53,036)	(137,562)
Rider USP			31,642,500			(2,370,023)	(6,147,220)
Rider EE			1,235,965			(92,574)	(240,112)
Interest - Customer Deposits			373,107			(27,946)	(72,484)
TAXES:							
Interest Synchronization (Table III)						(691,253)	(1,792,928)
TOTALS	<u>0</u>	<u>0</u>	<u>451,877,551</u>	<u>0</u>	<u>0</u>	<u>(34,536,883)</u>	<u>(89,579,633)</u>

TABLE III
Columbia Gas of Pennsylvania, Inc
INTEREST SYNCHRONIZATION
R-2025-3053499

	Amount \$
Company Rate Base Claim	3,861,622,942
ALJ Rate Base Adjustments	<u>0</u>
ALJ Rate Base	3,861,622,942
Weighted Cost of Debt	<u>2.60500000%</u>
ALJ Interest Expense	100,595,278
Company Claim (1)	<u>0</u>
Total ALJ Adjustment	(100,595,278)
Company Adjustment	<u>(91,366,271)</u>
Net ALJ Interest Adjustment	(9,229,007)
State Income Tax Rate	<u>7.49%</u>
State Income Tax Adjustment	<u>(691,253)</u>
Net ALJ Interest Adjustment	(9,229,007)
State Income Tax Adjustment	<u>(691,253)</u>
Net ALJ Adjustment for F.I.T.	(8,537,754)
Federal Income Tax Rate	<u>21.00%</u>
Federal Income Tax Adjustment	<u><u>(1,792,928)</u></u>

(1) Company Main Brief

TABLE IV
Columbia Gas of Pennsylvania, Inc
CASH WORKING CAPITAL - Interest and Dividends
R-2025-3053499
OCA

Accrued Interest		Preferred Stock Dividends		
	Long-Term Debt	Short-Term Debt		
Company Rate Base Claim	\$3,861,622,942	\$3,861,622,942	Company Rate Base Claim	\$3,861,622,942
ALJ Rate Base Adjustments	<u>\$0</u>	<u>\$0</u>	ALJ Rate Base Adjustments	<u>\$0</u>
ALJ Rate Base	\$3,861,622,942	\$3,861,622,942	ALJ Rate Base	\$3,861,622,942
Weighted Cost of Debt	<u>2.48900000%</u>	<u>0.11600000%</u>	Weighted Cost Pref. Stock	<u>0.00000000%</u>
ALJ Annual Interest Exp.	<u>\$96,115,795</u>	<u>\$4,479,483</u>	ALJ Preferred Dividends	<u>\$0</u>
Average Revenue Lag Days	0.0	0.0	Average Revenue Lag Days	0.0
Average Expense Lag Days	<u>0.0</u>	<u>0.0</u>	Average Expense Lag Days	<u>0.0</u>
Net Lag Days	<u>0.0</u>	<u>0.0</u>	Net Lag Days	<u>0.0</u>
Working Capital Adjustment				
ALJ Daily Interest Exp.	\$263,331	\$12,273	ALJ Daily Dividends	\$0
Net Lag Days	<u>0.0</u>	<u>0.0</u>	Net Lag Days	<u>0.0</u>
ALJ Working Capital	\$0	\$0		\$0
Company Claim (1)	<u>\$0</u>	<u>\$0</u>	Company Claim (1)	<u>\$0</u>
ALJ Adjustment	<u>\$0</u>	<u>\$0</u>		<u>\$0</u>
Total Interest & Dividend Adj.	<u>\$0</u>			
(1) Company Main Brief.				

TABLE V
Columbia Gas of Pennsylvania, Inc
CASH WORKING CAPITAL -TAXES
R-2025-3053499

Description	Company Proforma Tax Expense Present Rates	ALJ Adjustments	ALJ Pro forma Tax Expense Present Rates	ALJ Allowance	ALJ Adjusted Taxes at Present Rates	Daily Expense	Net Lead/ Lag Days	Accrued Tax Adjustment
PUC Assessment	\$0	\$0	\$0	\$0	\$0	\$0.00	0.00	\$0
Public Utility Realty	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
Capital Stock Tax	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
	\$0	\$0	\$0		\$0	\$0.00	0.00	\$0
State Income Tax	\$0	(\$34,536,883)	(\$34,536,883)	\$0	(\$34,536,883)	(\$94,621.60)	0.00	\$0
Federal Income Tax	\$0	(\$89,579,633)	(\$89,579,633)	\$0	(\$89,579,633)	(\$245,423.65)	0.00	\$0
	<u>\$0</u>	<u>(\$124,116,516)</u>	<u>(\$124,116,516)</u>	<u>\$0</u>	<u>(\$124,116,516)</u>			

ALJ Allowance	0
Company Claim (1)	<u>0</u>
ALJ Adjustment	<u>0</u>

(1) Company Main Brief

TABLE VI
Columbia Gas of Pennsylvania, Inc
CASH WORKING CAPITAL -- O & M EXPENSE
R-2025-3053499

Description	Company Pro forma F.T.Y. Expense	ALJ	ALJ Pro forma Expenses	Lag Days	Lag Dollars
Service Company	\$0	\$0	\$0	0.00	\$0
Chemicals	\$0	\$0	\$0	0.00	\$0
Group Insurance	\$0	\$0	\$0	0.00	\$0
Insurance, Other	\$0	\$0	\$0	0.00	\$0
Labor	\$0	\$0	\$0	0.00	\$0
Leased Equip./Rent	\$0	\$0	\$0	0.00	\$0
Leased Vehicles	\$0	\$0	\$0	0.00	\$0
Miscellaneous	\$0	\$0	\$0	0.00	\$0
Natural Gas	\$0	\$0	\$0	0.00	\$0
Power	\$0	\$0	\$0	0.00	\$0
Purchased Water	\$0	\$0	\$0	0.00	\$0
Telephone	\$0	\$0	\$0	0.00	\$0
Waste Disposal	\$0	\$0	\$0	0.00	\$0
Post Retirement Benefits	\$0	\$0	\$0	0.00	\$0
Pensions	\$0	\$0	\$0	0.00	\$0
	<u>\$0</u>	<u>\$0</u>	<u>\$0</u>	<u>0.00</u>	<u>\$0</u>
ALJ Average Revenue Lag	0.0				
Less: ALJ Avg. Expense Lag	<u>0.0</u>				
Net Difference	0.0	Days			
ALJ Pro forma O & M Expense per Day	<u>\$0</u>				
ALJ CWC for O & M	\$0				
Less: Company Claim (1)	<u>\$0</u>				
ALJ Adjustment	<u><u>\$0</u></u>				

(1) Company Main Brief

APPENDIX B
(PUBLIC VERSION)

OCA Proposed Findings of Fact

I. Summary of Public Input Hearing Testimony

1. At the public input hearings in this proceeding, Columbia customers testified that they are struggling to pay their current Columbia bills and are worried about the effect that the proposed increase will have on their communities, especially during a time of high inflation affecting household expenses like rent and grocery prices.¹
2. At the public input hearings in this proceeding, Columbia customers testified that Columbia's proposed residential customer charge increase is regressive, disproportionately affects low-income customers and seniors on fixed incomes, and affects customers' ability to improve their ability to afford their bills through usage reduction.²
3. At the public input hearings in this proceeding, Columbia customers testified that the vast majority of their Columbia bills are distribution charges and are not commodity costs.³
4. At the public input hearings in this proceeding, Columbia customers testified that the Company's frequency of rate case filings in recent years is increasing their rates substantially.⁴
5. At the public input hearings in this proceeding, Columbia customers testified that Columbia's Weather Normalization Adjustment Pilot resulted in substantial bill increases with few credits and that the proposed Weather Normalization Adjustment and Revenue Normalization Adjustment should be denied because it charges them for natural gas consumption they do not use.⁵

II. Overall Position on Rate Case

6. Columbia's request for an additional \$110.5 million in annual revenue far exceeds the amount of revenue necessary for it to provide safe, reliable, and adequate service at just and reasonable rates to its 446,000 customers. Instead, Columbia could

¹ Tr. 138, 140, 179, 180, 182, 182-83, 187, 189-90, 216, 217, 219, 225-26, 227, 228.

² Tr. 180, 187.

³ Tr. 66, 169, 182, 216, 226; Evans Exh. 1.

⁴ Tr. 168, 179, 189, 215-16, 217.

⁵ Tr. 169, 172, 173, 181, 187-88, 218, 218-19, 219, 233, 234.

provide safe and adequate service at just and reasonable rates with an annual revenue decrease of \$36.3 million.⁶

7. Columbia collects the highest revenue per unit of natural gas in the Commonwealth, and the third-highest for the 25 NGDCs offering service in the mid-Atlantic region, surpassed only by NGDCs offering service to New York City.⁷
8. Columbia has requested a rate increase 10 times since 2009, including five rate increases requested since 2020.⁸
9. In exchange for the Company's obligation to serve its captive customers, Columbia does not face risks associated with a competitive market, receives a monopoly franchise and an opportunity to recover a return of all prudently incurred expenses and capital investment, as well as a return on the value of property placed into public service; this bargained-for exchange is known as the regulatory compact.⁹
10. "Regulatory lag has long been recognized as a key component of the overall regulatory compact given the discipline it can impose on utility operational and investment decisions."¹⁰
11. In the time between rate cases, a utility must be disciplined in how it incurs expenses and makes capital investment.¹¹
12. "[T]he reduce incentives to overcapitalize and increase incentives to cost efficiencies, which are beneficial to ratepayers by reducing a utility's long-term costs," such as investment relating to non-revenue-generating safety and reliability plant improvements.¹²
13. Regulatory lag reduces incentives to overcapitalize and increases incentives to cost efficiencies, which are beneficial to ratepayers by reducing a utility's long-term costs.¹³

⁶ OCA St. 2 at 3; OCA St. 2SR at 3.

⁷ OCA Exh. MWD-7.

⁸ OCA St. 5 at 7.

⁹ OCA St. 1 at 14.

¹⁰ *Id.* at 7-9.

¹¹ *Id.* at 8.

¹² OCA St. 1 at 11.

¹³ OCA St. 1 at 11.

14. The statements made by Columbia and its parent company, NiSource Inc., suggest “that regulatory lag is already being effectively managed” by Columbia.¹⁴
15. Despite decreasing usage per customer trends, the Company’s revenue per customer has continued to increase over time.¹⁵
16. “If anything, the challenge for the Company has been, and continues to be, its cost efficiencies... revenues are not the problem and offering the Company any form of revenue cushion or insulation only makes it whole for continued cost inefficiencies.”¹⁶
17. Columbia has presented no evidence that customers would benefit under the proposed permanent Weather Normalization Adjustment or Revenue Normalization Adjustment mechanisms.¹⁷
18. Columbia seeks to provide the same level and quality of service and request rate increases with the same frequency while eliminating risks inherent in its own ability to perform.¹⁸
19. Columbia is well aware of the risks inherent in providing natural gas distribution service, including that customers’ usage of natural gas has been declining over time as a result of improved efficiency in home appliances and reduced throughput for heating purposes.¹⁹
20. Usage reduction trends are reflected in the Company’s calculation of its billing determinants for the purposes of designing rates.²⁰

III. Rate Base

A. Utility Plant in Service

21. Columbia is projecting net plant additions (gross plant additions less retirements) of \$436,529,280 for the future period ending November 30, 2025, and an additional

¹⁴ OCA St. 1 at 16.

¹⁵ OCA Exh. MWD-5.

¹⁶ OCA St. 1 at 27-28.

¹⁷ OCA St. 1 at 40-41; OCA St. 1 at 55.

¹⁸ OCA St. 1 at 30-39.

¹⁹ Columbia St. 2 at 10-12.

²⁰ Columbia St. 2 at 10-12.

\$436,492,629 for the fully projected future test year period ending December 31, 2026.²¹

22. Columbia included an inflation rate factor of 4% for 2025 and 5% for 2026 in its projected rate base balance.²²
23. Inflation-related adjustments “should not be used for ratemaking purposes because they do not provide a good index of cost increases, but rather reflect an overall broad, blanket-type economic adjustment that are typically applied to baskets of goods and services that may or may not be related or reflective to costs that are expected to be incurred by Columbia.”²³
24. Data provided by the Company indicates that its inflation factors were calculated using historical inflation data, which are an inaccurate representation of what levels of inflation will actually be experienced in the future.²⁴
25. OCA witness Mugrace recommended disallowance of the Company’s request to apply 4% and 5% inflation rates to arrive at total 2025 and 2026 capital expenditure replacements for an adjustment of \$(14,507,711) to the Company’s claimed plant in service balance. Disallowance will result in a revenue requirement decrease of approximately \$1.42 million.²⁵

B. Accumulated Depreciation

26. Accumulated depreciation “is a measure of the state of the system at any given time” and includes the sum of depreciation accruals collected through depreciation rates over the life of plant placed into service, also referred to as the “depreciation reserve.”²⁶
27. Accumulated depreciation is expressed as a negative value and is applied to utility plant in service, in addition to other rate base adjustments, to calculate the net plant in service value on which a utility earns a return.²⁷

²¹ OCA St. 2 at 4; Columbia Exhibit 108 at 3.

²² OCA St. 2 at 7.

²³ OCA St. 2 at 7-8.

²⁴ OCA St. 2SR at 5-6.

²⁵ OCA St. 2SR at 6; OCA Exh. DM-SR-5.

²⁶ OCA St. 3, App’x C.

²⁷ OCA St. 3 at 49.

28. OCA witness Mugrace calculated that, based on his recommended disallowance to the Company's request utility plant in service balance, an adjustment of \$(236,476) to accumulated depreciation must also be made.²⁸
29. OCA witness Garrett recommended an overall reduction to Columbia's depreciation expense claim of \$45,802,423 based on his recommendation that the Company utilize the Average Life Group procedure instead of the Equal Life Group procedure when calculating its depreciation rates for the purposes of depreciation expense.²⁹
30. Based on OCA witness Garrett's recommended adjustment to depreciation expense, OCA witness Mugrace made a corresponding reduction to Columbia's claimed accumulated depreciation of \$45,802,423.³⁰
31. OCA witness Mugrace recommended an overall reduction of \$46,038,899 to the Company's claimed depreciation reserve of \$927,212,098 for an overall recommended balance of \$881,173,199 based on his two adjustments of \$(236,476) and \$(45,802,423).³¹

C. Cash Working Capital

32. Columbia included a cash working capital claim for its materials and supplies, prepayments and gas storage underground balances.³²
33. In its cash working capital claim, the Company included a Gross Domestic Product (GDP) inflation factor of 2.93% for 2025, and the 3.05% GDP inflation factor for 2026.³³
34. OCA witness Mugrace recommended the removal of this inflation factor because it results in an increase that is not known and measurable and they does not reflect the true costs of providing service.³⁴
35. OCA witness Mugrace's adjusted cash working capital balance represents a reduction for materials and supplies of \$56,977 and a reduction of prepayments of

²⁸ OCA St. 3 at 49; OCA Exh. DM-6, DM-32.

²⁹ OCA Exh. DJG-17.

³⁰ OCA St. 2 at 10; OCA Exh. DM-SR-6.

³¹ OCA St. 2 at 10; OCA Exh. DM-SR-6.

³² OCA St. 2 at 10; Columbia Exh. 108.

³³ OCA St. 2 at 11.

³⁴ OCA St. 2 at 11.

\$262,481 for a net decrease of \$319,457. This reduces Columbia’s working capital balance to \$56,625,024.³⁵

D. Accumulated Deferred Income Tax

- 36. Based on OCA witness Mugrace’s recommendation to remove inflation-related adjustments to the Company’s claimed plant in service balance, OCA witness Mugrace recommended a corresponding adjustment to Columbia’s requested Accumulated Deferred Income Taxes (ADIT) balance of \$(67,372).³⁶
- 37. In Columbia’s claimed capitalized materials and supplies/prepayments balance, the Company included inflation adjustments of 2.93% and 3.05%.³⁷
- 38. OCA witness Mugrace recommended removing the inflation-related adjustment and adopting the Company’s 2025 baseline level of \$5,315,070, resulting in an adjustment of \$(891,093). This adjustment reduces the revenue requirement by approximately \$31,280.³⁸

E. Consolidated Tax Adjustment

- 39. The 50% portion of Columbia’s consolidated tax adjustment obligation prior to Act 40 is satisfied due to its expectation of investing \$329.3 million in the FPFTY period in infrastructure projects.³⁹
- 40. Columbia has not specifically identified how it will use the remaining 50% for general corporate purposes.⁴⁰
- 41. For the consolidated tax adjustment obligation, general corporate purposes “include uses for such ‘differential’ revenues as supporting capital expenditures necessary to execute utility business plans, paying off debt, funding construction projects, paying dividends, paying for maintenance and operating expenses, investing in utility plant in Pennsylvania, and providing a source of working capital.”⁴¹

³⁵ OCA St. 2 at 12; OCA Exh. DM-3.

³⁶ OCA St. 2 at 13; OCA Exh. DM-7.

³⁷ OCA St. 2SR at 8.

³⁸ OCA St. 2SR at 8.

³⁹ OCA St. 2 at 47.

⁴⁰ OCA St. 2 at 47.

⁴¹ OCA St. 2 at 47-48.

- 42. OCA witness Mugrace recommended that Columbia be required to commit 50% of its consolidated tax expense adjustment, or \$2,263,821, to utility working capital to its usage for general corporate purposes. This adjustment reduces the revenue requirement by approximately \$2.359 million.⁴²
- 43. The OCA's recommended rate base balance is \$3,861,622,942, which is \$16,241,227 higher than the Company's proposed Rate Base balance of \$3,845,381,715.⁴³

IV. Revenues

- 44. The OCA did not propose any adjustments to the Company's claimed present rate revenues of \$919,007,833.⁴⁴

V. Depreciation Expense

- 45. Annual depreciation expense is the return of a utility's investment in plant which collected through the life of the plant.⁴⁵
- 46. Depreciation rates are determined in a depreciation study using a depreciation system.⁴⁶
- 47. The basic components of a depreciation system are: (1) methods, (2) procedures, (3) techniques, and (4) models.⁴⁷
- 48. OCA witness Garrett "used the straight-line method, the average life group procedure, the remaining life technique, and the broad group model."⁴⁸
- 49. "The 'average life' and 'equal life' grouping procedures are the two most common."⁴⁹
- 50. "While single units may be analyzed for depreciation, employing a grouping procedure allows for composite application of depreciation rates to groups of similar

⁴² OCA St. 2SR at 9; OCA Exh. DM-SR-3.

⁴³ OCA St. 2SR at 4.

⁴⁴ OCA St. 2 at 15.

⁴⁵ OCA St. 2 at 42; OCA St. 2SR at 25; OCA Exh. DM-SR-32.

⁴⁶ OCA St. 3 at 60.

⁴⁷ OCA St. 3 at 60.

⁴⁸ OCA St. 3 at 60.

⁴⁹ OCA St. 3, App. C at 4-5.

property as opposed to excessively conducting calculations for each unit of property.”⁵⁰

51. Currently, Columbia uses the ALG procedure for plant installed prior to 1976 and the ELG procedure for plant installed in 1976 and subsequent years.⁵¹
52. “Under the ALG procedure, a constant accrual rate is calculated based on the average life of all property in the group.”⁵²
53. Use of the ALJ procedure “results in the same depreciation rate applied to each age interval.”⁵³
54. “Under the ELG procedure property is divided into subgroups (also referred to as ‘vintages’) that each have a common life.”⁵⁴
55. Columbia’s use of the ELG depreciation procedure instead of the ALG procedure “has an impact of approximately \$45 million to depreciation expense as of the 2026 depreciation study.”⁵⁵
56. Adopting the ALG procedure reduces Columbia’s proposed revenue requirement by \$63.615 million.⁵⁶
57. “[T]he ALG method results in a fairer application of depreciation rates compared to the ELG method given the realities of ratemaking proceedings.”⁵⁷
58. Use of the ELG method increases annual depreciation accrual charge to customers by approximately \$1.6 million.⁵⁸
59. “[T]he ALG method is used by analysts and adopted by regulators in the vast majority of jurisdiction and in the vast majority of cases.”⁵⁹

⁵⁰ OCA St. 3, App. C at 3.

⁵¹ Columbia St. 5 at 4; Tr. 318-19.

⁵² OCA St. 3 at 61.

⁵³ OCA St. 3 at 61.

⁵⁴ OCA St. 3 at 61.

⁵⁵ OCA St. 3SR at 14.

⁵⁶ OCA St. 2SR at 25-26.

⁵⁷ OCA St. 3 at 66.

⁵⁸ OCA St. 3 at 66.

⁵⁹ OCA St. 3 at 61.

60. Under ALG, the depreciation rates are consistent and predictable as the same depreciation rate is used throughout the service life of the account.⁶⁰
61. “Under the ELG procedure, customers rates (not just depreciation rates), would need to be adjusted every year in order for the ELG procedure to produce accurate depreciation rates.”⁶¹
62. Depreciation rates calculated under the ELG procedure result in higher depreciation rates in early years relative to later years.⁶²
63. Under the ELG procedure, the depreciation reserve grows disproportionately fast in earlier years, producing mismatches between revenues and expenses.⁶³
64. The ALG procedure keeps annual depreciation expense proportional to the depreciation reserve buildup and properly matches revenues and expenses.⁶⁴
65. The ALG procedure equitably spreads the annual depreciation expense on rate base investment over the generations of customers that receive service from the investments (i.e., favors intergenerational equity).⁶⁵
66. The ELG procedure assigns more depreciation expense to customers that take service early in the asset’s service life and reduces the expense to customers toward the end of the asset’s service life, which directly results in intergenerational inequity and discrimination in rates.⁶⁶
67. Columbia did not rebut the fact that the ELG charges ratepayers more in the early years of an asset’s life in service compared to the ALG method.⁶⁷
68. The Indiana Utility Regulatory Commission and Kentucky Public Service Commission have recently required regulated public utilities within their jurisdictions to switch from the ELG to the ALG procedure.⁶⁸

⁶⁰ OCA St. 3 at 64.

⁶¹ OCA St. 3SR at 13-14.

⁶² OCA St. 3 at 61.

⁶³ OCA St. 3 at 63.

⁶⁴ OCA St. 3 at 63.

⁶⁵ OCA St. 3SR at 13.

⁶⁶ OCA St. 3SR at 13.

⁶⁷ OCA St. 3SR at 13.

⁶⁸ OCA St. 3 at 63-64.

69. Columbia's continued use of the ELG procedure imposes an unjustified and unreasonable \$63.615 million revenue requirement burden on ratepayers, inflates the depreciation expense balance by approximately \$45 million, and represents approximately 58% of Columbia's revenue requirement increase request.⁶⁹
70. OCA witness Garrett's depreciation rates were calculated using the same service life parameters proposed in Columbia's depreciation study. No service life adjustments were recommended by OCA witness Garrett. The only difference is that OCA witness Garrett uses the ALG procedure while Columbia witness Spanos uses the ELG procedure.⁷⁰

VI. O&M and A&G Expenses

71. The OCA recommends that the Company's claimed operating expense balance, excluding depreciation, be reduced by \$16,757,680.⁷¹

A. Inflation Adjustments

72. "Inflation/deflation types factors to adjust for costs are not reasonable because these types of increase adjustments are not known and measurable and they do not reflect the true costs of providing service. These types of costs are basically blanket type increases/decreases which do not directly relate to actual costs expected to be incurred by the Company in the period for which rates are to be set."⁷²

B. Labor

73. Columbia proposes a labor expense balance of to \$38,770,674.⁷³
74. Columbia has historically maintained a vacancy rate ratio of 4.3812%.⁷⁴
75. OCA witness Mugrace recommended a labor balance of \$(1,698,606) by multiplying the Company's proposed labor expense of \$38,770,674 by the vacancy rate ratio of 4.3812%.⁷⁵

⁶⁹ OCA St. 2SR at 26.

⁷⁰ OCA St. 3 at 69.

⁷¹ OCA Exh. DM-SR-9.

⁷² OCA St. 2 at 25.

⁷³ OCA St. 2 at 16.

⁷⁴ OCA St. 2 at 16.

⁷⁵ OCA St. 2 at 16; OCA Exh. DM-SR-10.

C. Incentive Compensation

- 76. Columbia proposes to include \$2,568,807 in total incentive compensation expenses in its revenue requirement the FPFTY period.⁷⁶
- 77. Only 30% of the Company's proposed incentive compensation weighting pertain to objectives that directly benefit ratepayers, with the remaining 70% weighted towards financial performance.⁷⁷
- 78. It is the responsibility of Columbia to share the burden of the portion of its incentive compensation plan rewarding financial performance.⁷⁸
- 79. OCA witness Mugrace recommends an adjustment of \$(1,798,165) to the Company's claimed incentive compensation expense of \$2,568,807 for an allowance of \$770,642.⁷⁹

D. Restricted Stock and Long Term Incentive (LTI)

- 80. Columbia included \$754,446 in Long-Term Incentive (LTI) stock awards in its labor costs for the FPFTY period, including performance share unit and restricted stock unit components.⁸⁰
- 81. Only 30% of the Company's proposed Long-Term Incentive (LTI) stock awards weighting pertain to objectives that directly benefit ratepayers, with the remaining 70% weighted towards financial performance.⁸¹
- 82. The recommends that only 30% of the Company's claimed LTI expense of \$754,446 be allowed for ratemaking purposes, or an adjustment of \$(528,112) for a total allowance of \$226,334.⁸²

⁷⁶ OCA St. 2 at 18.

⁷⁷ OCA St. 2 at 20.

⁷⁸ OCA St. 2SR at 13.

⁷⁹ OCA St. 2SR at 13.

⁸⁰ OCA St. 2 at 21.

⁸¹ OCA St. 2SR at 12-13.

⁸² OCA St. 2 at 21.

E. Other Employee Benefits

83. Columbia proposes to recover \$8,915,459 in other employee benefits in the FPFTY period.⁸³
84. As OCA witness Mugrace incorporated a vacancy rate ratio of 4.3812% for Columbia’s labor expense, a corollary adjustment to Columbia’s Other Employee Benefits is necessary for the FPFTY period.⁸⁴

F. Outside Services

85. Columbia requests \$19,014,191 in outside services for the FTY and \$18,013,909 for the FPFTY.⁸⁵
86. Columbia included an inflation adjustment of 2.93% for the FTY and 3.05% for the FPFTY related to non-recoverable consulting costs (lobbying) and advertising.⁸⁶
87. Outside Services costs historically varied from a low of 4.52% to a high of 31.36% with a three-year average for 2022 through 2024 of 8.57%.⁸⁷
88. The variances in Outside Services expenses “existed for a reason as the Company has changed its scope and scale of work activity, which is a part of the cost of doing business.”⁸⁸
89. OCA witness Mugrace recommended using the 8.57% three-year average to normalize this expense based upon the historical costs, or a reduction of \$(1,444,261) to the Company’s claimed allowance. This adjustment results in an approximately \$2 million decrease to revenue requirement.⁸⁹

G. Corporate Insurance

90. Columbia proposed \$4,452,228 for Corporate Insurance in the FPFTY.⁹⁰

⁸³ OCA St. 2 at 23; Columbia Exh. 104 Sch. 1.

⁸⁴ OCA St. 2 at 23.

⁸⁵ OCA St. 2 at 24.

⁸⁶ OCA St. 2 at 24.

⁸⁷ OCA St. 2SR at 15.

⁸⁸ OCA St. 2SR at 15.

⁸⁹ OCA St. 2SR at 15; OCA Exh. DM-SR-14.

⁹⁰ OCA St. 2 at 26.

- 91. Columbia included a 3.05% inflation factor for the FPFTY when calculating its requested Corporate Insurance expense.⁹¹
- 92. OCA witness Mugrace recommended disallowing the inflation factor, which results in an adjusted balance of \$4,320,454, which is a \$131,774 revenue requirement reduction compared to Columbia's proposal.⁹²

H. Injury and Damages

- 93. Columbia proposed \$405,057 for Injury and Damage (I&D) expense.⁹³
- 94. Columbia included inflation factors when calculating its proposal.⁹⁴
- 95. OCA witness Mugrace removed the inflation-related adjustments to the Company's claimed I&D expense for a proposed adjustment of \$(51,257) to the Company's claimed balance of \$405,057 for a total allowance of \$353,800.⁹⁵

I. Employee Expenses

- 96. Columbia's Employee Expenses of \$554,925 in the HTY and \$637,383 in the FPFTY include employee recognition gifts, event tickets used for employee morale or team building purposes, and other entertainment expenses that support employee engagement.⁹⁶
- 97. The OCA recommends that 50% of the Company's Meals and Entertainment, or \$24,083, be allowed in rates.⁹⁷
- 98. Columbia witness Leal corrected the Company's employee expense claim, identifying that \$417,305 of the claimed expense balance related to clothing allowance and not to gifts and entertainment expenses.⁹⁸

⁹¹ OCA St. 2 at 26.

⁹² OCA St. 2 at 27; OCA Exh. DM-SR-17.

⁹³ OCA St. 2 at 27.

⁹⁴ OCA St. 2 at 27-28.

⁹⁵ OCA St. 2 at 27.

⁹⁶ OCA St. 2 at 28-29.

⁹⁷ OCA St. 2 at 29.

⁹⁸ OCA St. 2SR at 16.

99. The \$417,305 for the Company’s updated expense is \$21,524 less than the total employee expense claim and the difference is attributed to “non-customer oriented costs.”⁹⁹
100. The sum of the \$(24,083) and \$(21,524) results in a total adjustment of \$(45,607).¹⁰⁰

J. Company Memberships

101. Columbia’s claimed a membership expense balance of \$682,796.¹⁰¹
102. Columbia’s membership expense balance includes 2.93% and 3.05% inflation adjustments and the inclusion of Chamber of Commerce dues.¹⁰²
103. Columbia’s customers see no benefit from the Company’s participation in these organizations, as they are related to civic causes or lobbying.¹⁰³
104. OCA witness Mugrace recommends that the inflationary adjustments and Chambers of Commerce dues be disallowed for a total adjustment of \$(258,217). This adjustment reduces Columbia’s revenue requirement by approximately \$353,000.¹⁰⁴

K. Utilities – Fuel Used in Company Operations

105. Columbia proposed a \$2,075,819 balance related to its Utilities and Fuel used in Company Operations for the FPFTY.¹⁰⁵
106. Columbia included deflation factors of 2.93% for the FTY balance and 3.05% for the FPFTY balance.¹⁰⁶
107. OCA witness Mugrace recommended disallowance of these deflation adjustment, adjusting the Company’s costs related to Utilities – Fuel Used in Company Operations by \$28,758, for a total recommended allowance of \$2,104,577.¹⁰⁷

⁹⁹ OCA St. 2SR at 16.

¹⁰⁰ OCA St. 2SR at 16.

¹⁰¹ OCA St. 2 at 31; OCA Exh. DM-SR-20.

¹⁰² OCA St. 2 at 30-31.

¹⁰³ OCA St. 2SR at 16-17.

¹⁰⁴ OCA St. 2SR at 17; OCA Exh. DM-SR-20.

¹⁰⁵ OCA St. 2 at 31; Columbia Exh. 104, Sch. 1 at 2.

¹⁰⁶ OCA St. 2 at 32.

¹⁰⁷ OCA St. 2 at 32; OCA Exh. DM-21.

L. Advertising

108. Columbia proposed \$391,359 in advertising expense for the FPFTY.¹⁰⁸
109. Columbia included deflation factors of 2.93% for the FTY balance and 3.05% for the FPFTY balance.¹⁰⁹
110. OCA witness Mugrace recommended disallowance of these inflation adjustments, resulting in an adjustment of \$(11,366) to the Company's proposed advertising expense of \$402,724 for a total allowance of \$391,358.¹¹⁰
111. The Company's materials and supplies account "2020 Facilities Maintenance and Repairs Materials" increased from "\$42,478 in 2022, \$174,598 in 2023 and \$946,461 in 2024."¹¹¹
112. The three-year average of these expenses is \$558,615.¹¹²
113. The Company's materials and supplies account "2020 Facilities Maintenance and Repairs Materials" improperly included costs which were inadvertently assigned outside services expense by the vendor.¹¹³
114. Columbia did not explain how the accounting error identified by its witness Vassalotti was corrected in the Company's rate filing or in rebuttal testimony.¹¹⁴
115. OCA witness Mugrace recommended a three-year normalization for this account and adjusted the claimed materials and supply expense of \$6,080,827 by \$(558,615) for a total allowance of \$5,522,212.¹¹⁵

¹⁰⁸ OCA St. 2 at 32; Columbia Exh. 104, Sch. 1 at 2.

¹⁰⁹ OCA St. 2 at 32.

¹¹⁰ OCA St. 2 at 32.

¹¹¹ OCA St. 2 at 33.

¹¹² OCA St. 2 at Exh. DM-SR-24.

¹¹³ OCA St. 2SR at 17.

¹¹⁴ OCA St. 2SR at 18.

¹¹⁵ OCA St. 2 at Exh. DM-SR-24.

M. NiSource Corporate Services Company (NCSC) Shared Services

116. The Company claimed an allowance of allocated affiliate service company charges of \$79,191,884 from the NiSource Corporate Services Company (NCSC), a sister company owned by Columbia’s parent company, NiSource Inc.¹¹⁶
117. OCA witness Mugrace recommends that \$7,669,077 of the Company’s claim be disallowed, for a final allowance of \$71,522,807. The totality of Mr. Mugrace’s recommended adjustments to the Company’s allocated portion of NCSC expenses results in a revenue requirement impact of approximately \$10.651 million.¹¹⁷
118. For the FPFTY, Columbia included \$4,012,229 in the portion of claimed NCSC expenses associated with Long-Term Incentive (LTI) compensation and stock awards in the form of Performance Share Units (PSU) and Restricted Stock Units (RSU) to employees at the level of Director and above.¹¹⁸
119. Unlike the LTI compensation expense the Company claimed for its own activities, the allocated LTI compensation expense from NCSC is not broken down by category.¹¹⁹
120. “[T]here is no way to discern whether the Restricted Stock / LTI compensation costs actually benefit ratepayers.”¹²⁰
121. OCA witness Mugrace recommends that \$4,012,229 from the claimed allocation of NCSC expense associated with the disallowance of the portion of NCSC expenses related to LTI.¹²¹
122. Columbia proposes to include a portion of NCSC allocated Supplemental Executive Retirement Plan (SERP) expense in rates for a requested allowance of \$136,102 in the FPFTY.¹²²

¹¹⁶ OCA St. 2 at 34.

¹¹⁷ OCA St. 2SR at 23.

¹¹⁸ OCA St. 2SR at 36.

¹¹⁹ OCA St. 2SR at 21.

¹²⁰ OCA St. 2SR at 21.

¹²¹ OCA St. 2SR at 21.

¹²² OCA St. 2 at 37.

- 123. “Under a SERP, the Company retains the benefits in the event an employee dies, leaves or quits the Company. The Company has access to the dollars in the SERP and gets the cash value of the plan.”¹²³
- 124. OCA witness Mugrace recommended disallowance of the recovery of SERP costs included within the allocated portion of NCSC expense for an adjustment of \$(136,102).¹²⁴
- 125. Columbia’s allocated share of NSCS expenses included a requested allowance of \$5,029,637 for short-term incentive compensation.¹²⁵
- 126. OCA witness Mugrace recommended that 70% of the allocated portion of NCSC STI expense be disallowed, consistent with his recommendation regarding the Company’s directly-incurred STI expense, or an adjustment of \$(3,520,746) for a recommended allowance of \$1,508,891.¹²⁶

N. Diversity, Equity, and Inclusion (DEI) Expense

- 127. Columbia included a \$130,450 net balance for Diversity, Equity, and Inclusion (DEI) costs.¹²⁷
- 128. Columbia did not present metrics designed or evaluated to demonstrate ratepayer value and “these appear to be costs to benefit the Company such as corporate branding, imaging and touting Company stewardships.”¹²⁸
- 129. OCA witness Mugrace recommends disallowance of the Company’s claimed DEI expense of \$130,450.¹²⁹

O. Rate Case Expense

- 130. Columbia claims \$1,321,000 of rate case expense normalized over 12 months.¹³⁰

¹²³ OCA St. 2 at 37.

¹²⁴ OCA St. 2SR at 19.

¹²⁵ OCA St. 2SR at 22-23.

¹²⁶ OCA St. 2SR at 23.

¹²⁷ OCA St. 2 at 28.

¹²⁸ OCA St. 2 at 19-20.

¹²⁹ OCA St. 2SR at 20.

¹³⁰ Columbia Exh. 104, Schedule 2 at 16.

131. Since 2018, the Company has filed six rate increase requests, equivalent to a rate case every fourteen months or 1.16 years.¹³¹
132. OCA witness Mugrace recommended normalizing Columbia's rate case expense over 14 months, instead of the Company's proposed normalization period of 12 months, which reduces Columbia's rate case expense from \$1,321,000 to \$1,138,793, or \$182,207. Accepting this adjustment produces an overall revenue requirement decrease of approximately \$253,000.¹³²

P. Uncollectible Expense

133. Columbia calculated its proposed uncollectible expense balance by including an uncollectible account factor of 0.01346130 in its gross revenue conversion factor of 1.38698.¹³³
134. OCA witness Mugrace recommends an adjustment to Columbia's claimed uncollectible expense of \$(488,873) consistent with the OCA's recommended revenue requirement decrease of \$36,316,933.¹³⁴

Q. Rider Universal Service Plan (USP)

135. Columbia proposed recovery of \$31,862,500 in the FPFTY related to its Rider USP for its universal service program reconciling mechanism, and \$1,235,965 in the FPFTY related to its Rider EE for its energy efficiency program reconciling mechanism.¹³⁵
136. Columbia does not budget internal CAP administrative costs or any universal service program at the program level and does not provide the constituent categories of costs within the claim administrative costs account.¹³⁶
137. "The purpose of recovering costs through the Rider USP is to ensure that budgeted (or projected) costs can be reconciled against actual costs."¹³⁷

¹³¹ OCA St. 2SR at 23.

¹³² OCA St. 2SR at 23-24; OCA Sch. DM-SR-28.

¹³³ OCA St. 2SR at 24-25; OCA Exh. DM-SR-1, DM-SR-9, DM-SR-29.

¹³⁴ OCA St. 2SR at 24-25; OCA Exh. DM-SR-1, DM-SR-9, DM-SR-29.

¹³⁵ Columbia Exh. 104, Sch. 1 at 2; OCA St. 2 at 41.

¹³⁶ OCA St. 5 at 112-14.

¹³⁷ OCA St. 5 at 113.

138. OCA witness Mugrace recommended a \$220,000 disallowance from the Rider USP balance. This adjustment reduces the revenue requirement by approximately \$306,000.¹³⁸

R. Depreciation and Amortization Expense

139. The Company proposed a depreciation and amortization expense of \$149,371,200 and a five-year net negative salvage expense of \$5,484,681.¹³⁹
140. OCA witness Garrett calculated that, if Columbia's depreciation expense were calculated using the ALG procedure instead of the ELG procedure, then the expense would be reduced by \$45,802,423.¹⁴⁰
141. OCA witness Mugrace recommended a depreciation expense balance adjustment of \$(45,802,423) consistent with the depreciation expense adjustment supported by OCA witness Garrett. This adjustment reduces Columbia's requested revenue requirement by \$63.615 million.¹⁴¹

VII. Taxes

A. Income Taxes

142. Columbia claimed a total income tax expense of \$72,811,341, including federal income tax, state income tax, deferred income tax, excess deferred income tax, and amortization of investment tax credit components.¹⁴²
143. Due to the recommendations made by OCA witnesses Mugrace and Garrett regarding the Company's claimed rate base, O&M expense, depreciation expense, capital structure, and return on equity, Mr. Mugrace recommended an income tax expense allowance of \$(55,267,855), which is \$17,543,486 greater than the Company's claimed income tax expense of \$(72,811,341).¹⁴³

¹³⁸ OCA St. 2SR at 25; OCA Exh. DM-SR-31.

¹³⁹ OCA St. 2 at 42.

¹⁴⁰ OCA Exh. DJG-17.

¹⁴¹ OCA St. 2SR at 25-26.

¹⁴² OCA St. 2 at 44.

¹⁴³ OCA St. 2SR at 4; OCA Exh. DM-SR-34.

B. Taxes Other Than Income Tax

144. The Company requested a taxes other than income expense allowance of \$4,500,883, which includes payroll taxes, property taxes, license and franchise, sales and use taxes and other taxes other than income taxes.¹⁴⁴
145. The Company's payroll tax rate is 7.2234%.¹⁴⁵
146. OCA witness Mugrace recommended that the Company's payroll tax obligation be updated based on his adjustment to labor and incentive compensation expenses for a payroll tax allowance of \$2,798,543, a reduction of \$187,573.¹⁴⁶
147. Columbia's composite property tax rate is 0.00026287%.¹⁴⁷
148. OCA witness Mugrace recommended that the Company's property tax obligation be updated based on his adjustment to the utility plant in service balance for a property tax allowance of \$1,368,336, a reduction of \$3,824.¹⁴⁸

VIII. Rate of Return

A. Introduction

149. Columbia proposed an excessive 11.35% return on equity which includes a 0.25% upward management performance adder adjustment.¹⁴⁹
150. Columbia requested a capital structure of 54.4% common equity and 45.6% debt, inclusive of short- and long-term debt components.¹⁵⁰
151. The OCA recommended a return on equity of 8.9%.¹⁵¹
152. The OCA recommended a capital structure of 50% common equity and 50% debt, inclusive of short- and long-term debt components, for ratemaking purposes.¹⁵²

¹⁴⁴ OCA St. 2 at 43.

¹⁴⁵ OCA St. 2 at 43.

¹⁴⁶ OCA St. 2 at 43.

¹⁴⁷ OCA St. 2 at 43.

¹⁴⁸ OCA St. 2 at 43.

¹⁴⁹ OCA St. 3 at 12.

¹⁵⁰ OCA St. 3 at 50; Columbia Exh. VVR-5.

¹⁵¹ OCA St. 3 at 3, 56.

¹⁵² OCA St. 3 at 3, 56.

153. The OCA recommended an overall cost of capital of 7.06%.¹⁵³

B. Capital Structure

154. OCA witness Garrett used the same utility proxy group as Columbia witness Rea, which contains six natural gas companies and is referred to as “Gas LDC Group.”¹⁵⁴

155. The “Combination Utility Group” proxy group and “Non-Regulated Utility Group” proxy group used by Columbia witness Rea add “no marginal value to the process of developing a reasonable estimate for Columbia’s cost of equity” beyond that of the “Gas LDC Group.”¹⁵⁵

156. The average capital structure mix for the “Gas LDC Group” consists of 55% debt and 45% equity.¹⁵⁶

157. The debt component of Columbia’s proposed capital structure of 46% is notably lower than the average debt component of the “Gas LDC Group.”¹⁵⁷

C. Debt Cost

158. The OCA accepted Columbia’s proposed debt cost rate as reasonable.

D. Cost of Common Equity

159. The OCA’s Discount Cash Flow (DCF) cost of equity analysis results are 7.5% using Value Line’s estimated growth rate and 7.3% using the U.S. Gross Domestic Product (GDP) as the sustainable growth rate input.¹⁵⁸

160. The OCA’s Capital Asset Pricing Model (CAPM) cost of equity analysis results are 8.9% using OCA witness Garrett’s capital structure and 8.7% using the Company’s requested capital structure.¹⁵⁹

¹⁵³ OCA St. 3 at 3, 56.

¹⁵⁴ OCA St. 3 at 12.

¹⁵⁵ OCA St. 3 at 57.

¹⁵⁶ OCA St. 3 at 50.

¹⁵⁷ OCA St. 3 at 50.

¹⁵⁸ OCA St. 3 at 27.

¹⁵⁹ OCA St. 3 at 31.

161. Since the time Columbia witness Rea conducted his analysis, Value Lines' betas have been notably reduced.¹⁶⁰
162. The most recent betas published by Value Line are more reflective of market expectations for the risk of a utility stock than the beats relied upon by Columbia witness Rea.¹⁶¹
163. Columbia witness Rea's earnings risk premium (ERP) to 7.17% is significantly higher than the ERPs estimated by expert surveys, Kroll (formerly Duff & Phelps), Dr. Damodaran, and that calculated by OCA witness Garrett.¹⁶²
164. Columbia witness Rea's proposed 0.43% size premium adjustment to his CAPM model results is unsupported by contemporary financial literature.¹⁶³
165. Columbia witness Rea's Risk Premium Model "adds no marginal value to estimating cost of equity beyond the CAPM" and significantly overstates the market-based cost of equity for Columbia.¹⁶⁴

E. Management Performance Premium

166. OCA witness Garrett is not aware of a regulator from another jurisdiction that specifically recognized management performance as having an increasing effect on the authorized ROE.¹⁶⁵
167. As investors in competitive firms in the marketplace cannot expect an additional return on equity simply due to prudent managerial performance, the Company as a regulated firm should not receive any premium in addition to an authorized market-based ROE due to prudent managerial performance.¹⁶⁶
168. Columbia has not demonstrated that its claimed performance with respect to obtaining LIHEAP assistance for its low-income customers, efforts to serve low-income customers, or customer service performance are exemplary.¹⁶⁷

¹⁶⁰ OCA St. 3 at 39.

¹⁶¹ OCA St. 3 at 39-40.

¹⁶² OCA St. 3 at 41.

¹⁶³ OCA St. 3 at 42-44.

¹⁶⁴ OCA St. 3 at 44-45.

¹⁶⁵ OCA St. 3 at 56.

¹⁶⁶ OCA St. 3 at 56.

¹⁶⁷ OCA St. 5 at 42; OCA St. 6 at 9.

IX. Revenue Allocation and Rate Design

A. Cost of Service Study

169. Columbia presented three different cost-of-service studies in this proceeding that differ in how they allocate the cost of mains: one using the Customer-Demand method, one using the Peak & Average method, and one using an average of the two.¹⁶⁸
170. The Peak & Average method does not include a customer component in its allocation of mains costs, recognizes the costs of peak demand, and recognizes the role that annual throughput plays in distribution system design and buildout.¹⁶⁹
171. The Company's main extension policy driving the connection of additional throughput to the system through a revenues test, instead of justifying the extension of mains merely because of the connection of a customer.¹⁷⁰

B. Revenue Allocation

172. Under Columbia's proposed revenue allocation, the LDS/LGSS customer class would receive a subsidy of \$19,252,450 and Flex rate customers would receive a subsidy of \$42,650,000 for a total of \$61,902,450 in inter-class cross-subsidization borne by chiefly residential and small business customers.¹⁷¹
173. Because Flex rate customers receive service at contract rates, any revenue allocated to the Flex rate customer class except through customer charge increases cannot be reasonably recovered by the Company.¹⁷²
174. Under the OCA's proposed revenue allocation, the subsidy being provided to LDS/LGSS customers would decrease by approximately \$3,397,637 as compared to the Company's proposal.¹⁷³
175. The OCA's recommendation is consistent with the principles of cost causation and gradualism.¹⁷⁴

¹⁶⁸ OCA St. 4 at 5.

¹⁶⁹ OCA St. 4 at 5.

¹⁷⁰ OCA St. 4R at 8.

¹⁷¹ OCA St. 4 at 10.

¹⁷² Columbia St. 6 at 20.

¹⁷³ OCA St. 4 at 10.

¹⁷⁴ OCA St. 4SR at 8.

176. OSBA witness Ewen and OCA witness Mierzwa “proposed the same revenue increases for the LDS/LGSS, MLDS and Flex rate customer classes, but different increases for the RSS/RDS, SGSS/DS-1, SGSS/DS-2, and SDS/LGSS customer classes.”¹⁷⁵
177. Under the OCA’s revenue allocation proposal, the subsidy Rates RSS/RDS, SGSS/DS-1, SGSS/DS-2, and SDS/LGSS provide to LDS/LGSS and Flex rate customers are essentially equalized, meaning that they pay the same share of the subsidy as compared to each other.¹⁷⁶
178. The residential customer class currently pays the highest proportion of subsidies provided to other customer classes relative to its revenues.¹⁷⁷
179. Under the OSBA’s proposal, the residential customer class would bear the highest proportion of the subsidies provided to other customer classes.¹⁷⁸
180. The most equitable result is for the costs of subsidizing the LDS/LGSS and Flex rate customers to be borne evenly between the four unsubsidized customer classes.¹⁷⁹

C. Rate Design/Tariff Structure

181. A customer charge should approximate customer-related costs directly attributable to a customer, or those “costs that change directly with its addition or subtraction of a customer.”¹⁸⁰
182. Columbia proposes to increase the fixed residential customer charge from \$17.25 per month to \$31.97 per month, an increase of \$14.72 or 85%.¹⁸¹
183. The Company currently charges the highest residential customer charge of any natural gas distribution company in Pennsylvania.¹⁸²

¹⁷⁵ OCA St. 4R at 4.

¹⁷⁶ OCA St. 4R at 4.

¹⁷⁷ OCA St. 4 at 11.

¹⁷⁸ OCA St. 4R at 4.

¹⁷⁹ OCA St. 4SR at 7-8.

¹⁸⁰ OCA St. 4 at 14.

¹⁸¹ OCA St. 4 at 14.

¹⁸² OCA St. 4 at 15.

184. The Company’s proposed residential customer charge of \$31.97 includes costs that do not vary with the addition or subtraction of a single customer, such as mains costs and uncollectible expenses.¹⁸³
185. Excluding mains and uncollectible costs from the Company’s customer cost analysis reduces the calculated customer charge to \$27.70, which is less than the \$31.97 proposed by Columbia.¹⁸⁴
186. Mains costs “are driven by the loads placed upon [the distribution system], not the number of customers served.”¹⁸⁵
187. Uncollectibles expense is not customer-related and should not be included in the residential customer charge.¹⁸⁶
188. The Company’s proposed residential customer charge increase is far greater than the 16% increase Columbia proposes for the residential customer class as a whole and is greater than the 14% increase for the residential customer class supported by OCA witness Mierzwa.¹⁸⁷
189. Based on the Company’s noticed usage amount of 70 therms and noticed bill impact of an increase of \$15.77 from \$138.52 to \$154.29, the portion of residential customers’ bills occupied by the customer charge would increase under the Company’s proposal. Based on a bill of \$138.52, the current customer charge comprises 12% of a current residential customer’s bill. Based on a bill of \$154.29, the Company’s proposed customer charge would comprise 21% of a residential customer’s bill.
190. “Increasing the fixed monthly customer charge increases the portion of a bill that a low-income customer cannot avoid by adjusting the customer’s usage.”¹⁸⁸
191. High energy burdens not only affect customers’ ability to pay their bills, but affect the quality of life for low-income customers.¹⁸⁹

¹⁸³ OCA St. 4 at 15-16.

¹⁸⁴ OCA St. 4 at 15-16.

¹⁸⁵ OCA St. 4 at 13-14.

¹⁸⁶ OCA St. 4SR at 3.

¹⁸⁷ OCA St. 4 at 9, 11.

¹⁸⁸ OCA St. 5 at 81.

¹⁸⁹ OCA St. 5 at 82.

192. The proposed customer charge increase represents an additional \$177 *each year* that Columbia’s low-income customers already struggling to afford their bills will be forced to pay without the opportunity to avoid the rate increase.¹⁹⁰
193. A very small portion (23%) of Columbia’s estimated low-income customer population are enrolled in the Company’s CAP, with only 40% of customers enrolled in Columbia’s CAP being enrolled in the percentage of income program (PIP) component of CAP, or less than 10% of the Company’s overall estimated low-income population.¹⁹¹
194. “Any increase in the Residential customer charge would reduce the incentive to engage in energy conservation and would limit the benefits residential customers can realize from engaging in energy conservation actions.”¹⁹²
195. The appropriate revenue allocation under a revenue requirement increase less than the Company’s proposal in its filing is a proportionate scale-back consistent with the revenue allocation proposal of OCA witness Mierzwa.¹⁹³

X. Alternative Ratemaking

A. Weather Normalization Adjustment

196. Pursuant to the Settlement Agreement resolving the Company’s 2024 rate increase request, which was approved by the Commission, the Company’s WNA Pilot will continue until an order is entered in this proceeding, as the first rate case filed by the Company after December 14, 2024.¹⁹⁴
197. The Company’s WNA is a ratemaking mechanism that adjusts customer bills during the winter heating season (November through May) based on deviations from what the Company defines as “normal” weather. Specifically, it applies a formula using the ratio of normal heating degree days (“HDDs”) to actual HDDs, multiplied by a customer-specific heating usage factor, to generate either a credit or a surcharge on

¹⁹⁰ OCA St. 5 at 87.

¹⁹¹ OCA St. 5 at 79.

¹⁹² OCA St. 4SR at 5-6.

¹⁹³ OCA St. 4 at 12.

¹⁹⁴ *Pa. PUC v. Columbia Gas of Pa., Inc.*, Docket No. R-2024-3046519 (Joint Petition for Settlement filed Aug. 28, 2024) at ¶ 35.

the bill. The WNA is limited to weather-related usage changes and applies to residential customers only.¹⁹⁵

198. Columbia’s WNA Pilot extracted approximately \$74 million in additional revenues for Columbia from customers subject to the WNA in the five most recent heating seasons.¹⁹⁶
199. In the five most recent hearing seasons, “the Company *never* issued a refund to consumers under the WNA despite claiming that the mechanism is symmetrical.”¹⁹⁷
200. The proposed WNA creates an inverse relationship between Columbia’s cost of service – as defined by the manner in which distribution rates are designed in Pennsylvania – and how those costs are recovered by recovering throughput- and demand-related costs through adjustments to customers’ usage.¹⁹⁸
201. The WNA neither operates to decrease Columbia’s ratio of peak demand to average demand nor insulate ratepayers from rate increases due to the inefficient usage of Columbia’s distribution system.¹⁹⁹
202. The proposed WNA adjusts customers’ heat-sensitive usage to increase – or, less likely, to decrease – their billed consumption based on differences in weather between the predicted “normal” and the actual weather experienced and does reflect customers’ level of demand associated with anticipated consumption.²⁰⁰
203. The proposed WNA enables inter- and intra-class cost-shifting.²⁰¹
204. The proposed WNA does not affect the Company’s disincentive to promote energy efficiency.²⁰²

¹⁹⁵ OCA St. 1 at 50.

¹⁹⁶ OCA St. 1 at 55; OCA Exh. MWD-11; CAUSE-PA St. 2-SR at 14.

¹⁹⁷ OCA St. 1 at 55 (emphasis in original).

¹⁹⁸ OCA Exh. MWD-1 at 3.

¹⁹⁹ OCA Exh. MWD-1 at 3.

²⁰⁰ OCA Exh. MWD-1 at 3.

²⁰¹ OCA Exh. MWD-1 at 3.

²⁰² OCA Exh. MWD-1 at 3.

205. The proposed WNA reduces customers' incentive to conserve or invest in energy efficiency measures by recapturing bill savings due to reduced usage during warmer-than-normal weather.²⁰³
206. The proposed WNA disproportionately harms Columbia's low-income customers.²⁰⁴
207. The proposed WNA does not provide rate stability, as evidenced by the fact that Columbia has filed a rate increase request, on average, every year and a half since the WNA Pilot was implemented.²⁰⁵
208. The proposed WNA reduces customers' bill stability and the Company's budget bill program provides better bill stability than the proposed WNA.²⁰⁶
209. The proposed WNA is likely to continue charging customers as weather becomes warmer over time.²⁰⁷
210. The proposed WNA "weaken[s] the positive impacts regulatory lag has on promoting cost containment between rate cases."²⁰⁸
211. The proposed WNA includes no check or cap on earnings, which means that there is no ceiling on how much revenue the proposed WNA can extract from Columbia's residential customers.²⁰⁹
212. "Customers have no means of anticipating future WNA charges as it is impossible for customers to forecast WNA charges in advance and likely difficult for customers to calculate even after the fact."²¹⁰
213. The Company's communication materials regarding the WNA Pilot are inadequate because they represent the WNA Pilot as working to the benefit of both customers and the Company, which has not historically been the case, and do not provide

²⁰³ OCA Exh. MWD-1 at 3.

²⁰⁴ OCA St. 5 at 79.

²⁰⁵ OCA Exh. MWD-1 at 3; OCA St. 5 at 7.

²⁰⁶ OCA St. 5 at 99-100.

²⁰⁷ Columbia St. 17 at 40-41.

²⁰⁸ OCA Exh. MWD-1 at 4.

²⁰⁹ OCA Exh. MWD-1 at 4.

²¹⁰ OCA Exh. MWD-1 at 4.

customers with an individualized calculation of that customer’s WNA charge or credit.²¹¹

- 214. Columbia has provided no evidence that the revenue extracted through the WNA pilot supported improvements in its reliability- and safety-related investments.²¹²
- 215. The Company has not proposed revisions or improvements to its WNA Pilot in the proposed WNA other than making it permanent and has not identified criteria or performance metrics by which the WNA Pilot would be evaluated.²¹³

B. Revenue Normalization Adjustment

- 216. Columbia’s proposed RNA “would compare actual base rate revenue per customer to the benchmark revenue per customer established in this proceeding. Any differences would be tracked monthly, adjusted for actual customer counts, and reconciled annually through a charge or credit to customers.”²¹⁴
- 217. The Company presented no evidence that its quality of service would improve as a result of the RNA.²¹⁵
- 218. The proposed RNA will likely result in net charges to customers subject to the RNA.²¹⁶
- 219. The Commission has not previously approved a full revenue decoupling mechanism.²¹⁷
- 220. The proposed RNA is contrary to cost causation principles by charging customers a fixed monthly surcharge due to unrecovered demand- and throughput-related costs from prior periods.²¹⁸
- 221. The proposed RNA does not improve customers’ capacity utilization.²¹⁹

²¹¹ OCA St. 6 at 23-25.

²¹² OCA Exh. MWD-1 at 4.

²¹³ OCA St. 1 at 53.

²¹⁴ OCA St. 1 at 17.

²¹⁵ Columbia Exh. JDT-2R at 4 (citing 52 Pa. Code § 69.3302(a)(14)).

²¹⁶ OCA St. 1 at 36-37.

²¹⁷ *PAWC 2023; Columbia 2020*.

²¹⁸ OCA Exh. MWD-1 at 1.

²¹⁹ OCA Exh. MWD-1 at 1.

- 222. Reductions in consumption associated with installing energy efficiency measures or conservation efforts – or due to large-scale economic pressures such as inflation or a global pandemic – would result in RNA charges the subsequent year.²²⁰
- 223. The proposed RNA would result in intra-class cross-subsidization between high- and low-usage customers.²²¹
- 224. The proposed RNA does not calculate the fixed monthly surcharge on a per-customer basis.²²²
- 225. The Company proposed an expansion of its Energy Efficiency Program which is not related to its proposal to implement an RNA.²²³
- 226. The proposed RNA would recapture a customer’s non-commodity-related bill savings due to reduced usage, conservation, or the installation of energy efficiency measures.²²⁴
- 227. The proposed RNA will likely disproportionately affect Columbia’s low-income customers.²²⁵
- 228. The proposed RNA will not improve customers’ rate stability.²²⁶
- 229. The proposed RNA does not cap the amount it can charge a customer in a given month.²²⁷
- 230. The proposed RNA will not reduce the number of rate increase requests filed by Columbia.²²⁸
- 231. The proposed RNA would recapture the portion of weather-sensitive usage which is not adjusted by the Company’s proposed WNA or WNA Pilot, including during months when the WNA’s deadband would eliminate a bill adjustment.²²⁹

²²⁰ OCA St. 1 at 15.

²²¹ OCA Exh. MWD-1 at 1.

²²² Columbia St. 17 at 47, 49.

²²³ OCA Exh. MWD-1 at 1.

²²⁴ OCA St. 1SR at 15.

²²⁵ OCA St. 5 at 79.

²²⁶ OCA Exh. MWD-1 at 2.

²²⁷ OCA St. 1 at 45.

²²⁸ OCA St. 1 at 48-49.

²²⁹ OCA Exh. MWD-1 at 2.

- 232. The proposed RNA would reduce the Company’s incentives to control costs and disincentives to overcapitalize between rate cases due to regulatory lag.²³⁰
- 233. The proposed RNA includes no consumer protections.²³¹
- 234. Over a number of years, the proposed RNA operates to guarantee Columbia’s collection of its authorized revenue requirement.²³²
- 235. The proposed RNA provides unconditional revenue decoupling without requiring Columbia to achieve performance-related objectives to warrant the opportunity to decouple its revenues from throughput.²³³
- 236. Columbia did not provide consumer education materials or a plan regarding how it will educate customers or bill them for the RNA.²³⁴
- 237. The proposed RNA would not improve Columbia’s system reliability.²³⁵

XI. Customer/Quality of Service

A. Root Cause Analysis

- 238. Columbia should be required to develop and implement a root cause analysis of customer disputes, informal and formal complaints, and BCS findings, particularly those identified as “verified” and “infractions” on a regular basis.²³⁶
- 239. “Columbia has a database that contains closed customer disputes and the results of BCS informal complaints, but there is no evidence of analysis of trends or internal actions undertaken in response to this information.”²³⁷
- 240. “Columbia has not conducted a root cause analysis of customer complaint trends.”²³⁸

²³⁰ OCA St. 1 at 46; OCA St. 1SR at 14.

²³¹ OCA MWD-1 at 2.

²³² Columbia St. 17 at 51.

²³³ OCA Exh. MWD-1 at 1.

²³⁴ OCA St. 6 at 23-26; OCA St. 6SR at 1-2.

²³⁵ OCA Exh. MWD-1 at 2.

²³⁶ OCA St. 6 at 17.

²³⁷ OCA St. 6 at 15-16.

²³⁸ OCA St. 6 at 15-16.

241. “Focusing solely on looking at individual complaints fails to recognize that a single complaint may reflect a more serious problem or concern.”²³⁹

B. Payment Arrangement Policy

242. Columbia should routinely evaluate its payment arrangements to identify the factors that contribute to the success or failure of its agreements and take steps to internalize the results of that analysis in its implementation of payment arrangements and communications with customers.²⁴⁰
243. “Columbia’s justified PAR [PARs are customer informal complaints to BCS about the terms of the utility’s payment arrangement] rate increased from .03 in 2021 to .06 in 2023.”²⁴¹
244. At present, Columbia does not evaluate the success or failure of its payment arrangements, and the Company has not undertaken any analysis of its termination and reconnection results.²⁴²

245. Columbia’s customer service representative training materials **BEGIN**
CONFIDENTIAL [REDACTED] **END**
CONFIDENTIAL²⁴³

C. Columbia Billing and Payment Policies

246. Columbia’s “bill properly educates the customer about the comparison of the NGS charges with the Price to Compare (natural gas supply prices and charges provided pursuant to the approved Default Service procurement plan). In [Columbia’s] customer bill, the disclosure of the PTC [price to compare] is located near the presentation of the NGS charges.”²⁴⁴
247. “Columbia’s residential (and non-residential) customers are vastly overpaying for essential natural gas supply when choosing an NGS instead of relying on the Price to Compare. From January 2022 through March 2025, approximately 48,000

²³⁹ OCA St. 6 at 16.

²⁴⁰ OCA St. 6 at 17.

²⁴¹ OCA St. 6 at 14-15.

²⁴² OCA St. 6 at 17.

²⁴³ OCA St. 6 at 18.

²⁴⁴ OCA St. 6 at 20.

residential customers paid \$35,332,095 MORE than the PTC. In only two months was there even a slight benefit from NGS prices.”²⁴⁵

- 248. “Columbia should exclude known low income customers from customer choice if it has not already done so.”²⁴⁶
- 249. Columbia should target educational messages to the choice customers to emphasize how to compare NGS charges per therm to the PTC and to urge them to compare prices and rates on a monthly basis.²⁴⁷
- 250. Columbia should be required to review its scripts for any automated chat box or “app” to ensure that all the customer rights associated with these transactions are provided for customers.²⁴⁸

XII. Universal Service Programs

A. Affordability

- 251. Columbia’s heating bills were 96% higher in 2025 than they were in 2012.²⁴⁹
- 252. For Columbia’s lowest income customers (with income levels at the lowest range of the Federal Poverty Level (FPL) (0 – 50%)), heating burdens are significantly higher than the affordable burden defined by the PUC of 4% of income. For Columbia’s other customers in the mid (50%-100% FPL) and highest (100-150% FPL) ranges of what is considered low-income, the heating burdens under Columbia’s rates exceed the affordable burden defined by the PUC of 6% of income.²⁵⁰
- 253. Forty percent “of the customers with Columbia Gas with the lowest incomes throughout its service territory were worse off in 2023 than they were in 2014 when comparing incomes to Columbia Gas prices.”²⁵¹

²⁴⁵ OCA St. 6 at 21.

²⁴⁶ OCA St. 6SR at 15.

²⁴⁷ OCA St. 6 at 21.

²⁴⁸ OCA St. 6 at 22; OCA St. 6SR at 15.

²⁴⁹ OCA St. 5 at 11.

²⁵⁰ OCA St. 5 at 8.

²⁵¹ OCA St. 5 at 15.

254. One in seven households, or 13.5%, in Columbia’s service territory have annual income less than \$10,000; one in four households have income less than \$15,000; and one in three households have income less than \$20,000.²⁵²
255. “[T]here is a significant low-income customer population that is *not* participating in CAP and that will be adversely affected by the Company’s proposed rate increase.”²⁵³
256. Low-income customer unaffordability impacts the operating costs such as the collection costs, working capital, uncollectibles that are then normalized and passed on through the next rate case.²⁵⁴
257. Inflation is disproportionately affecting lower-income households.²⁵⁵
258. An authorized return on equity appropriately considers the effect of a potential rate increase on customers’ ability to afford their utility bills.²⁵⁶
259. The proposed rate increase impacts moderate income households, as assessed by the ALICE (Asset-Limited, Income-Constrained, Employed) Survival Budget, as “there is a significant population living with incomes greater than the Federal Poverty Level, but less than that which is needed to meet basic living expenses.”²⁵⁷
260. “High cost-of-living areas demonstrate identifiable affordability problems when considering natural gas bills.”²⁵⁸

B. Recommendations to Address Low-Income Unaffordability

261. “Over the [most recent] 24 month period, excluding the winter months with no shutoffs, Columbia disconnected service to 12,254 Confirmed Low-Income customers, while entering into only 10,894 payment arrangements in those same months.”²⁵⁹

²⁵² OCA St. 5 at 21.

²⁵³ OCA St. 5 at 24.

²⁵⁴ OCA St. 5 at 26.

²⁵⁵ OCA St. 5 at 28.

²⁵⁶ OCA St. 5 at 31.

²⁵⁷ OCA St. 5 at 41.

²⁵⁸ OCA St. 5 at 46.

²⁵⁹ OCA St. 5 at 66.

262. “The average arrears at the time of disconnection [for Confirmed Low-Income customers] ranged from a low of \$757 to a high of \$1,579.”²⁶⁰
263. Columbia should initiate a screening process at the time a household first applies to receive service from Columbia to determine whether the applicant: (1) should be classified as a Confirmed Low-Income customer; and (2) should be referred to the CAP application process.²⁶¹
264. Half of the Confirmed Low-Income customers disconnected are not being reconnected.²⁶²
265. The Company’s self-service workflow do not provide a reference to the fact that a low-income customer is exempt, by both statute and PUC regulation, from being required to post a cash security deposit.²⁶³
266. Columbia proposed a two-year pilot in which the Company would provide a one-time grant to assist with the payment of outstanding arrearage balances for customers who are otherwise eligible to re-enter the Company’s CAP.²⁶⁴
267. The Rider USP “is not a mechanism for Columbia Gas to use to recover costs imposed by federal and state agencies.”²⁶⁵
268. Columbia “has not established the propriety of collecting the EAT costs through the Rider USP.”²⁶⁶
269. Columbia has done very little cross-program implementation that relates to other low-income programs and CARES is not a category of costs recoverable through the Rider USP.²⁶⁷

²⁶⁰ OCA St. 5 at 66.

²⁶¹ OCA St. 5SR at 16.

²⁶² *Id.*

²⁶³ OCA St. 5 at 78.

²⁶⁴ Columbia St. 16 at 3.

²⁶⁵ OCA St. 5 at 114.

²⁶⁶ OCA St. 5SR at 17.

²⁶⁷ OCA St. 5 at 114.

XIII. Energy Efficiency Programs

- 270. Columbia’s EE&C Plan includes three energy efficiency programs designed to reduce natural gas consumption by 2.7 million Dth in the first year savings over the three-year Plan.²⁶⁸
- 271. Phase II continues the Residential Prescriptive (RP) and Online Audit Kit (OAK) programs from Phase I and also adds a Small Commercial program.²⁶⁹
- 272. The total proposed cost of the Plan is \$7,884,579 over the three plan years with annual budgets from \$2.5 million to \$2.8 million.²⁷⁰
- 273. In order to develop the forecasted levels of participation, the Company relied upon its historical performance from Phase I, market data from the 2018 Act 129 Residential Baseline Survey, market data from the 2018 Act 129 Residential Baseline Survey, the 2009 Residential Energy Consumption Survey, Columbia Gas Rate Division Data Request on Residential customer forecasts, and climate data.²⁷¹
- 274. In Rebuttal, Company Nunley stated that the Company would adopt the OCA’s recommendation to update its compliance filing to incorporate the most recent market information and will do so in future filings.²⁷²
- 275. “The Company should coordinate with the EDCs in which its service territory overlaps on energy efficiency offerings, including thermostats and weatherization to avoid customer and contractor confusion.”²⁷³
- 276. “Adoption of weatherization measures can reduce the size of the heating equipment due to a tighter envelope.”²⁷⁴
- 277. “The Company should encourage the adoption of weatherization measures prior to the implementation of new heating equipment.”²⁷⁵

²⁶⁸ OCA St. 7 at 2-3.

²⁶⁹ OCA St. 7 at 3.

²⁷⁰ OCA St. 7 at 3.

²⁷¹ OCA St. 7 at 8.

²⁷² Columbia St. 13-R at 11.

²⁷³ OCA St. 7 at 11.

²⁷⁴ OCA St. 7 at 11-12.

²⁷⁵ OCA St. 7 at 11-12.

278. The same vendor which assisted the Company to develop its Energy Efficiency Plan is the same vendor which provides an evaluation of the success of the Plan.²⁷⁶
279. “While GEEG may be qualified for both roles, for them to provide both services to the same energy efficiency portfolio removes the impartial perspective that is expected from evaluation of energy efficiency programs.”²⁷⁷

XIV. Tariff Issues (Not Addressed Above)

A. Rate EDDS

280. The Company requests Commission authorization to implement a new tariff schedule, the Economic Development Distribution Service Rate (Rate EDDS).²⁷⁸
281. The Company “has recently received an inquiry from a potential customer that may qualify for service under the proposed EDDS rate schedule” but the Company’s discussions with the prospective customer are still preliminary.²⁷⁹

B. Eligible Customer Lists

282. Columbia proposed to broaden the scope of private customer information it will be able to provide to undisclosed third-parties under its tariff.²⁸⁰
283. Columbia filed a letter with the Commission to serve as notice of its plan to implement the practice of “on-bill” billing for Columbia customers.²⁸¹

²⁷⁶ OCA St. 7 at 12-13.

²⁷⁷ OCA St. 7SR at 4.

²⁷⁸ OCA St. 1 at 58.

²⁷⁹ Columbia St. 9-R at 35.

²⁸⁰ OCA St. 6 at 17.

²⁸¹ *Pa. PUC v. Columbia Gas of Pa. Inc.*, Docket No. G-2025-3056022, Letter (June 30, 2025) (June 30, 2025 Letter).

OCA Proposed Conclusions of Law

I. Overall

1. The regulation of utilities is one of the most important functions traditionally associated with the police power of the States.¹
2. The Public Utility Code (Code) governing sales that are only rationally dealt in by a monopoly is a proper exercise of the state police power to regulate the health, safety, morals, and general welfare of citizens.²
3. Columbia Gas of Pennsylvania, Inc. (Columbia) is a public utility as defined in Section 102 of the Public Utility Code.³
4. The Commission has jurisdiction over the parties and the subject matter of this proceeding.⁴
5. The utility requesting the rate increase has the burden of establishing the justness and reasonableness of every element of its requested rate increase.⁵
6. Columbia has the burden of proving that every element of its proposed rates are just and reasonable.⁶
7. A utility which relies on the use of a fully projected future test year “in discharging its burden of proof,” and must provide “appropriate data evidencing the accuracy of the estimates contained in the future test year or a fully projected future test year.”⁷
8. As a matter of law, a public utility’s rates must be just and reasonable and in conformity with regulations or orders of the Commission.⁸

¹ *Ark. Elec. Coop. Corp. v. Ark. Pub. Serv. Comm’n*, 461 U.S. 375, 377 (1983) (*Ark. Elec.*).

² *Relief Elec. Light, Heat & Power Co's. Petition*, 63 Pa. Super. 1, *5-10 (1916), 1916 Pa. Super. LEXIS 89, **6-15 (*Relief Elec.*); *Jenkins Twp. v. Pub. Serv. Comm’n*, 65 Pa. Super. 122 (1916), 1916 Pa. Super. LEXIS 30, **15-16 (*Jenkins Twp.*).

³ 66 Pa. C.S. § 102.

⁴ 66 Pa. C.S. § 101, *et seq.*

⁵ 66 Pa. C.S. §§ 315(a), 1301; *Lower Frederick Twp. Water Co. v. Pa. PUC*, 409 A.2d 505, 507 (Pa. Cmwlth. 1980).

⁶ 66 Pa. C.S. §§ 315(a), 1301, and 1308(e).

⁷ 66 Pa. C.S. § 315(e).

⁸ 66 Pa. C.S. § 1301(a).

9. A public utility may obtain “a rate that allows it to recover those expenses that are reasonably necessary to provide service to its customers[,] as well as a reasonable rate of return on its investment.”⁹
10. The Commission “has broad discretion in determining whether rates are reasonable” and “is vested with discretion to decide what factors it will consider in setting or evaluating a utility’s rates.”¹⁰
11. The Commission has the “power to make and apply policy” concerning the appropriate balance between rates charged to consumers and returns allowed to utility investors.¹¹
12. Given that a utility’s general rate increase request will substantially affect the interests of consumers, the Commission must “consistent with its other statutory responsibilities, take such action with due consideration to the interests of consumers.”¹²
13. If a utility is not providing adequate, efficient, safe, and reasonable service, then the rates that it charges for that service are not just and reasonable.¹³
14. During the course of a Section 1308(d) general rate increase request, the Commission “shall consider, in addition to all other relevant evidence of record, the efficiency, effectiveness and adequacy of service of each utility when determining just and reasonable rates.”¹⁴
15. If a utility’s service is found to be inadequate, then the Commission “shall give effect to this section by making such adjustments to specific components of the utility’s claimed cost of service as it may determine to be proper and appropriate” as supported by the evidence in the proceeding.¹⁵
16. Columbia has not met its burden of proving its requested annual revenue increase of \$110.5 million will produce just and reasonable rates.

⁹ *City of Lancaster Sewer Fund v. Pa. PUC*, 793 A.2d 978, 982 (Pa. Cmwlth. 2002) (*Lancaster 2002*).

¹⁰ *Popowsky v. Pa. PUC*, 683 A.2d 958, 961 (Pa. Cmwlth. 1996) (*Popowsky 1996*).

¹¹ *Popowsky v. Pa. PUC*, 665 A.2d 808, 812 (Pa. 1995).

¹² 71 P.S. § 309-5.

¹³ 66 Pa. C.S. §§ 1301, 1501; *see Nat’l Utils. v. Pa. PUC*, 709 A.2d 972, 973 (Pa. Cmwlth. 1998) (holding that whether rates are just and reasonable is inextricably intertwined with the quality of service provided).

¹⁴ 66 Pa. C.S. § 523(a).

¹⁵ *Id.*

17. The OCA's adjustments to the overall revenue requirement are supported by substantial evidence of record.
18. An overall revenue requirement decrease of no less than \$36,316,933, as based on the OCA's fully-substantiated adjustments, will produce rates that are just and reasonable, equitable among customer groups, and in the public interest, will allow Columbia to recover its reasonable costs, have an opportunity to earn a fair rate of return, and maintain its financial stability to provide safe and adequate service to consumers.

II. Rate Base

19. The use of broad inflation adjustments to estimate the cost of additional plant undermines the ratemaking concept of "used and useful" and certainly does not rise to the level of meeting Columbia's burden of proof in this proceeding.¹⁶
20. The Commission has repeatedly required specificity by the utility when the utility uses an inflation factor to estimate cost increases in the test year, and the Commission has disallowed inflation factors that are too speculative in nature.¹⁷
21. In *Aqua 2022*, the Commission stated, "allowing Aqua to apply a general inflation adjustment to a block of expenses could incentivize less accurate tracking of expenses and a less rigorous approach to controlling costs for those expenses."¹⁸
22. Under Act 40 of 2016, codified at Section 1301.1 of the Code, regulated public utilities are required to used 50% of excess rates collected for the purpose of paying income tax "to support reliability or infrastructure related to the rate-base eligible capital investment" and 50% for "general corporate purposes."¹⁹

III. Revenues

23. Columbia met its burden of proof regarding its claimed revenues.

¹⁶ See 66 Pa. C.S. § 102; *Pa. PUC v UGI Utilities, Inc. - Electric Division*, R-2017-2640058, Order (Oct. 25, 2018) (*UGI 2018*) at 27-31, 79; 66 Pa.C.S. § 315(a); *Burleson*, 461 A.2d at 1236.

¹⁷ *Pa. PUC v. Phila. Elec. Co.*, 58 Pa. P.U.C. 7 (1983) (*PECO 1983*); *Nat'l Fuel Gas Dist. Corp. v. Pa. PUC*, 677 A.2d 861 (Pa. Cmwlth. 1986) (*NFG 1986*).

¹⁸ *Pa. PUC v Aqua Pa. Water Co.*, 2022 Pa. PUC LEXIS 161, *50-51 (Order entered May 16, 2022) (*Aqua 2022*).

¹⁹ 66 Pa. C.S. § 1301.1.

IV. Depreciation Expense

24. The U.S. Supreme Court defined depreciation as follows: “depreciation is the loss, not restored by current maintenance, which is due to all the factors causing the ultimate retirement of the property. These factors embrace wear and tear, decay, inadequacy, and obsolescence.”²⁰
25. Under Pennsylvania Court precedent, annual depreciation is defined as follows: “Annual depreciation is an operating expense representing the consumption of assets in rendering service.”²¹
26. “A utility is entitled under the law to recover from the rate payers the original cost of construction of its depreciable plant.”²²
27. Additionally, “it is clear in our law that ‘[i]n no event will a utility be permitted to recover by annual allowances for depreciation a total amount in excess of the original cost, since annual depreciation is computed on original cost and not upon fair value or reproduction cost.’”²³
28. The Pennsylvania Superior Court defined accrued depreciation (also referred to as accumulated depreciation) as follows: “[a]ccrued depreciation for rate purposes means ‘the actual depreciation of the utility’s property as it has accrued to the date that fair value is in issue.’”²⁴
29. The Superior Court further noted that “accrued depreciation properly determined ‘should disclose the consumption of property to date.’”²⁵
30. While the Company is entitled to recover depreciation expense to ensure the utility is whole and the integrity of its investment maintained, the utility bears the burden of demonstrating that its claimed amounts to recover in expenses are not excessive.²⁶
31. “[T]he company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct.

²⁰ *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 167 (1934) (*Lindheimer*).

²¹ *Penn Sheraton Hotel v. Pennsylvania Public Utility Com.*, 198 Pa. Super. 618, 627 (*Penn Sheraton*).

²² *Penn Sheraton* at 627.

²³ *Penn Sheraton* at 627.

²⁴ *Penn Sheraton* at 624.

²⁵ *Penn Sheraton* at 624.

²⁶ 66 Pa. C.S. § 315(a); see *Lindheimer*, 292 U.S. at 169; *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 606 (1944) (*Hope*).

The calculations are mathematical, but the predictions underlying them are essentially matters of opinion.”²⁷

32. “[T]his Court recognized in [*Lindheimer*], the propriety of basing annual depreciation on cost. By such a procedure the utility is made whole and the integrity of its investment maintained. No more is required.”²⁸
33. The Commonwealth Court has stated that the Commission is not bound by any particular methodology or procedure in determining annual depreciation expense.²⁹
34. The Superior Court stated “it is recognized that accrued depreciation is essentially a judgment figure, based on all the evidence, and the weight to be given any particular estimate is for the commission. The commission is not bound to accept any particular method of estimating accrued depreciation.”³⁰
35. The Commonwealth Court in *Pa. Power* held that “[i]n a rate case, both annual depreciation expense allowance and accrued depreciation should be calculated on a reasonably consistent basis.”³¹
36. “Although the PUC may be guided by its finding of accrued and annual depreciation in a prior case or cases, in determining such items in a rate case currently before it, such prior findings are not res judicata.”³²
37. The “reasonably consistent basis” language used by the Commonwealth Court specifically relates to the calculation of accrued depreciation and annual depreciation in determining just and reasonable rates.³³
38. Merely because a utility used a depreciation procedure in the past is neither a justification nor a limitation for determining what constitutes just and reasonable rates in this proceeding.³⁴

²⁷ *Lindheimer* at 169.

²⁸ *Hope*, 320 U.S. at 606.

²⁹ *Pa. Power & Light Co. v. Pa. Pub. Util. Com.*, 311 A.2d 151, 158 (Pa. Cmwlth. 1973) (*Pa. Power*) (citing *Pittsburgh v. Pa. Pub. Util. Comm’n*, 222 A. 2d 395 (Pa. Super. 1966) (*Pittsburgh*) and *Philadelphia v. Pa. Pub. Util. Comm’n*, 102 A. 2d 428 (Pa. Super. 1954) (*Philadelphia*)).

³⁰ *Pittsburgh* 222 A.2d at 401-402 (upholding a Commission decision to give less weight to a utility’s depreciation study as the Commission had considered all relevant factors in connection with accrued depreciation).

³¹ *Pa. Power* at 158.

³² *Pa. Power* at 158.

³³ *Pa. Power* at 158.

³⁴ *Pa. Power* at 158.

39. Instead, both accrued and annual depreciation must be reasonably consistent with each other.³⁵
40. The Public Utility Code and Commissions' regulations do not require that a utility's currently utilized depreciation procedure for certain plant must be accepted indefinitely.³⁶
41. The U.S. Supreme Court stated that the public utility bears the burden of proof regarding operating expenses for depreciation.³⁷
42. The use of the ELG procedure is not consistent with the well-established "matching principle" of ratemaking requires that expenses, revenue, and rate base match over the same time period.³⁸
43. If post-test year additions to expenses and revenues are allowed, "the balance established by the test year is lost and the matching principle is violated."³⁹
44. Two basic principles of public utility ratemaking are that: 1) a public utility only earns money from its rate base and 2) a public utility does not earn money on its expenses.⁴⁰
45. "A utility is not permitted to pad its estimates of annual depreciation so as to meet unknown contingencies, or to compensate for possible future errors in judgment."⁴¹
46. Columbia's use of the ELG procedure results in intergenerational inequity. As stated in *Re Minnegasco, Inc.* "[a]s a general rule, it is inequitable and economical [sic] unsound to ask one 'generation' of captive ratepayers to bear the cost of providing service to another."⁴²
47. Section 1304 of the Public Utility Code prohibits discrimination in rates.⁴³

³⁵ *Pa. Power* at 158.

³⁶ 66 Pa. C.S. § 1703; 52 Pa. C.S. § 73.9(c).

³⁷ *Lindheimer* at 175.

³⁸ *Pa. PUC v. NFGD*, 1994 Pa. PUC LEXIS 135, *13 (*NFGD*).

³⁹ *NFGD* at *13; *Re. Niagra Mohawk Power Co.*, 1986 N.Y. PUC LEXIS 3, *97 (a plant running for 50 years but packing all of its depreciation accruals into the first 40 years would violate generational equity and the matching principle).

⁴⁰ *Pa. Power* at 159.

⁴¹ *Pa. Power* at 157.

⁴² *Re Minnegasco, Inc.*, 143 PUR4th 419, 426 (May 3, 1993); *Re Limerick Nuclear Generating Station*, 1982 Pa. PUC LEXIS 102, *65.

⁴³ 66 Pa. C.S. § 1304.

48. The ELG procedure is an accelerated form of depreciation, which causes current customers to pay greater depreciation expense than future customers for the same level of utility service, resulting in intergenerational inequity.⁴⁴
49. In Duke Energy Indiana's (Duke Indiana) 2020 base rate case, Duke proposed using the ELG procedure, which had been adopted by the Indiana commission in previous cases, and the Indiana Utility Regulatory Commission found that the ELG procedure resulted in unreasonable rates.⁴⁵
50. The Kentucky Public Service Commission found that the ELG procedure front-loads depreciation expense in earlier years and decreases it in later years, resulting in a mismatch between revenues and expenses.⁴⁶
51. Substantial record evidence further demonstrates that use of the ALG procedure will allow the Company's accumulated depreciation and annual depreciation to be calculated on a reasonably consistent basis.

V. O&M and A&G Expenses

52. The PUC is empowered to disallow expenses of a utility that it concludes are of no direct benefit to ratepayers.⁴⁷
53. The Commission should reject all claimed expense increases that are not supported by targeted or specific data demonstrating increases to each claimed expense.⁴⁸ Blanket inflation adjustments, such as the ones proposed by Columbia in its filing, were recently disallowed by the Commission in *PGW 2023*.⁴⁹
54. In *PGW 2023*, the Commission rejected PGW's request to apply a blanket 4.63% inflation adjustment to 20% of its expenses because it was applied broadly and did not meet the "'known and measurable' standard for increasing each FTY expense claim in the FPFTY."⁵⁰

⁴⁴ *Re Limerick Nuclear Generating Station*, 1982 Pa. PUC LEXIS 102, *65.

⁴⁵ OCA St. 3 at 62.

⁴⁶ *Application of Duke Energy Kentucky, Inc.*, Case No. 2017-00321, Order at 26-27 (Apr. 13, 2018) (*Duke Kentucky*).

⁴⁷ *Phila. Elec. Co. v. Pa. PUC*, 552 A.2d 342, 346 (Pa. Cmwlth. 1989).

⁴⁸ *Aqua 2022* at *50-51.

⁴⁹ *Pa. PUC v. Phila. Gas Works*, Docket No. R-2023-3037933 (Order entered Nov. 9, 2023) (*PGW 2023*) at 72.

⁵⁰ *Pa. PUC v. Wellsboro Electric Co.*, R-2019-3008208 (Order entered Apr. 29, 2020) (*Wellsboro 2020*).

55. In *Wellsboro 2020*,⁵¹ the Commission determined that the utility bears the burden of proving that its inflationary adjustments represent known and measurable changes to costs over time and that all adjusts to expense claims “directly relate[] to the actual costs expected to be incurred in each expense account in the FPFTY.”⁵²
56. Columbia should not be permitted to recover expense increases that it has not demonstrated are known and measurable.⁵³
57. The Commission has previously accepted OCA adjustments premised on the use of a vacancy rate ratio for Columbia Gas.⁵⁴
58. The Commission disfavors speculative estimates of spending and found, “the parties have correctly cited our precedent for the proposition that a speculative estimates, based on estimated totals of future costs, are not a preferred method for billing future expenses.”⁵⁵
59. Where an incentive compensation plan is reasonable, prudently incurred, not excessive, and there is a benefit to ratepayers, a Company may recover the expense of that program.⁵⁶
60. In *PPL 2012* the Commission allowed incentive compensation expense because it was consistent with the Commission’s “prior decisions approving incentive compensation programs that are focused on improving operational effectiveness.”⁵⁷
61. In *Aqua 2022*, the Commission found that Aqua’s stock-based compensation was linked to performance objectives that benefit consumers, as they were linked to providing quality service at a reduced cost.⁵⁸
62. The Commission has approved incentive compensation plans where employees eligible for the compensation “have direct responsibilities for customer service and

⁵¹ *Wellsboro 2020* at 40.

⁵² *Wellsboro 2020* at 40.

⁵³ 66 Pa. C.S. § 315(e).

⁵⁴ *PGW 2023* at 59.

⁵⁵ *Pa. PUC v. Pa. Power & Light Co.*, 85 Pa. PUC 306 at 115 (1995).

⁵⁶ *Pa. PUC v. PPL Elec. Util. Corp.*, R-2012-2290597 (Order entered Dec. 28, 2012) (*PPL 2012*).

⁵⁷ *PPL 2012* at 26 (citing *Pa. PUC v. Aqua Pa., Inc.*, 2008 Pa. PUC LEXIS 50, *24; *Pa. PUC v. Duquesne Light Co.*, 1987 Pa. PUC LEXIS 342 at *99-100).

⁵⁸ *Pa. PUC v Aqua Pa. Water Co.*, 2022 Pa. PUC LEXIS 161 (Order entered May 16, 2022) (*Aqua 2022*) at **60-61.

regulatory compliance or are otherwise responsible for ensuring safe and reliable service to customers.”⁵⁹

63. Having a financial metric component to the incentive compensation plan does not disqualify it from inclusion in the utility’s revenue requirement, if the incentive plan establishes that eligibility for the incentive “is based on performance duties and metrics directly related to the provision of service.”⁶⁰
64. Under the Public Utility Code, utilities are not permitted to recover the costs of “membership fees, dues or charges to fraternal, social or sports clubs or organizations.”⁶¹ Columbia’s customers see no benefit from the Company’s participation in these organizations, as they are related to civic causes or lobbying; as a result, the Company should not be able to recover the costs of memberships which reflect its corporate citizenship and should be incurred below-the-line.⁶²
65. Normalization adjustments are made to eliminate any unusual activity or event, or to stabilize fluctuations in expenses which would not reasonably be expected to recur in the future. In other words, normalization is a ratemaking technique used to smooth out the effects of an expense item that occurs at regular intervals in irregular amounts.⁶³

VI. Rate of Return

66. The Pennsylvania Superior Court has held that the capital structure of utilities that are wholly-owned subsidiaries may not be one which it would maintain if it were obliged to obtain its debt and equity financing on the open market rather than from a parent company.⁶⁴
67. “The use of the actual capital structure in such peculiar circumstances might be unfair to either the utility or its customers, depending upon whether debt or equity

⁵⁹ *Pa. PUC v. Pa.-American Water Co.*, 2021 PA. PUC LEXIS 55 at *59 (Order Feb. 25, 2021) (*PAWC 2021*).

⁶⁰ *PAWC 2021* at *60.

⁶¹ 66 Pa. C.S. § 1316.1.

⁶² *Cf. Pa. PUC v. Columbia Gas of Pa.*, Docket No. R-2022-3032167, 2023 PA. PUC LEXIS 173 at *27 (Order entered June 15, 2023); *cf. Pa. PUC v. Pa.-American Water Co.*, Docket No. R-00038304, 2003 Pa. PUC LEXIS 498 (Order entered Nov. 26, 2003) at *145.

⁶³ *Pa. PUC v. Phila. Gas Works*, Docket No. R-2023-3037933, Order at 82-83 (Nov. 9, 2023) (*PGW 2023*) (citing *Pa. PUC v. Total Environmental Solutions, Inc.*, Docket Nos. R-00072493 (Order July 30, 2008) (*TESI*) at 72).

⁶⁴ *Riverton Consol. Water Co. v. Pa. PUC*, 140 A.2d 114 at 121 (Pa. Super. 1958).

is disproportionately high. Under such circumstances the commission must make adjustments based upon substantial evidence in order to reach a fair result.”⁶⁵

68. Columbia failed to support its proposed capital structure and return on equity with substantial evidence.
69. OCA’s proposed capital structure for ratemaking purposes of 50% equity and 50% debt is consistent with the requirements of law.
70. The Commission has previously stated: “We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return.”⁶⁶
71. A reasonable return on equity consistent with the requirements of *Hope* and *Bluefield* is 8.9%.
72. Columbia did not present evidence sufficient to conclude that it is entitled to a return on equity increase of 0.25% for superior management performance.
73. The OCA’s proposed overall weighted rate of return of 7.09% is supported by substantial evidence.
74. The appropriate rate of return for Columbia is 7.09%.

VII. Revenue Allocation and Rate Design

75. Cost of service is a forward-looking exercise which allocates to future beneficiaries their share of the costs incurred to provide them with service.⁶⁷
76. “[D]istribution mains exist and are related to both annual demands and peak demands. Both annual and peak demands must be recognized in the allocation of distribution mains cost if the allocation is to be in accord with the principle of cost-causality.”⁶⁸
77. “[A]lthough mains serve customers, it is the throughput that determines the type of main investment because it is the load that determines the main investment, not the number of customers served. The existence of one customer, five customers, or ten

⁶⁵ *Riverton Consol. Water Co. v. Pa. PUC*, 140 A.2d 114 at 121 (Pa. Super. 1958).

⁶⁶ *Pa. PUC v Aqua Pennsylvania, Inc.*, Docket No. R-2021-3027385, 2022 Pa PUC LEXIS 161, *83, (Opinion and Order entered May 16, 2022) (*Aqua 2022*).

⁶⁷ *Phila. Indus. and Comm. Gas Users Group v. Pa. PUC*, 2025 Pa. Cmwlt. LEXIS 133, * 38 (Pa. Cmwlt. Aug. 1, 2025) (*PICGUG*).

⁶⁸ *Columbia 2020* at 217; *PGW 2023* at 137.

customers does not determine the amount of mains investment. Mains investment is driven by the loads placed upon it, not by the number of customers served.”⁶⁹

78. “Commission precedent, including the proceeding for the *2007 PGW Rate Case*, and the recent proceeding in *Columbia 2020*, weigh against the idea that mains costs include a customer component.”⁷⁰
79. Columbia’s Peak & Average Allocated Cost of Service Study is supported by substantial evidence.
80. Columbia’s Peak & Average Allocated Cost of Service Study is consistent with Commission precedent and should be adopted.
81. The Commission considers the results of costs of service studies to address ratemaking concerns such as unreasonable inter- and intra-class subsidization through revenue allocation.⁷¹
82. The Commission may also consider non-cost factors when determining the appropriate cost of service for each class.⁷²
83. Revenue allocation should seek to eliminate class cross-subsidization and move customer classes towards their cost of service.⁷³
84. The Commission is charged with balancing public policy considerations such as gradualism, incentivizing conservation, and ensuring that rates are affordable for all customers when allocating revenues between classes.⁷⁴
85. A proposed rate increase is consistent with the principles of gradualism if it is between 1.5 and 2.0 the system average increase.⁷⁵
86. Columbia’s proposed revenue allocation causes inter-class cross-subsidization to persist beyond reasonable levels.
87. The OCA’s proposed revenue allocation is supported by substantial evidence.

⁶⁹ *Id.* at 217 (citing *Pa. PUC v. Nat’l Fuel Gas Dist. Corp.*, Docket No. R-00942991, 1994 Pa. PUC LEXIS 134, 83 Pa. P.U.C. 262 (Order Dec. 6, 1994) at 91-92).

⁷⁰ *PGW 2023* at 137 (citing *Pa. PUC v. Phila. Gas Works*, Docket No. R-00061931, *et al* (Order entered September 28, 2007) at 80) (citing also *Columbia 2020* at 217).

⁷¹ *Lloyd v. Pa. PUC*, 904 A. 2d 1010, 1020 (Pa. Cmwlth. 2006).

⁷² *Phila. Elec. Co. v. Pa. PUC*, 470 A.2d 654, 658 (Pa. Cmwlth. 1984); *Hoover v. Pa. R.R.*, 27 A. 282, 283 (Pa. 1893).

⁷³ *Lloyd v. Pa. PUC*, 904 A. 2d 1010, 1020 (Pa. Cmwlth. 2006).

⁷⁴ *PGW 2023* at 146; *PECO Gas 2020* at 247.

⁷⁵ *Columbia 2020* at 233; *PECO Gas 2020* at 249-50.

88. The OCA's proposed revenue allocation is consistent with Commission precedent regarding the principles of gradualism and should be adopted.
89. "Rate design requires a careful balance of the competing interests of customer classes as well as prudent application of the principles of cost causation, gradualism, and overall fairness."⁷⁶
90. A customer charge should approximate customer-related costs directly attributable to a customer, or those "costs that change directly with its addition or subtraction of a customer."⁷⁷
91. In considering movement towards cost-of-service for the approximation of direct customer costs in a customer charge, the Commission also considers important policy issues, such as gradualism, the effect on conservation, affordability, and other policy objectives.⁷⁸
92. The Commission has previously relied upon the direct cost method of determining customer charges based on the cost of service, where only the costs directly associated with the connection or removal of a customer from the system are considered in the customer charge.⁷⁹
93. While the Commission has recognized that indirect customer costs, "such as employee benefits, local taxes and other general and administrative costs . . . may be considered for inclusion in the customer charge, [] such claims are subject to scrutiny on a case-by-case basis."⁸⁰
94. The inclusion of all customer-related costs in a customer charge, even if they are "fixed," may make the customer charge unreasonable; rather, indirect customer costs are "includable in a customer charge cost analysis."⁸¹
95. In Pennsylvania, demand-related costs are recovered through volumetric rates, as are throughput-related costs, such as the costs associated with distribution mains.⁸²

⁷⁶ *PECO Gas 2020* at 274.

⁷⁷ OCA St. 4 at 14.

⁷⁸ *Columbia 2020* at 264.

⁷⁹ *Pa. PUC v. PPL Gas Utilities Corporation*, Docket No. R-00061398, 2007 Pa. PUC LEXIS 2 at *210 (Order entered Feb. 8, 2007) (*PPL Gas 2007*).

⁸⁰ *Pa. PUC v. Aqua Pa., Inc.*, Docket No. R-00038805, 2004 Pa. PUC LEXIS 39 at *98 (Order entered July 23, 2004) (*Aqua 2004*).

⁸¹ *Pa. PUC v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597 (Order entered Dec. 5 2012) (*PPL Electric 2012*) at 131.

⁸² *PGW 2023* at 163.

96. Columbia has not met its burden of proof that its proposed residential customer charge would result in just and reasonable rates.
97. A residential customer charge of \$17.25 is supported by substantial evidence in this proceeding.

VIII. Alternative Ratemaking

98. Under Section 1330 of the Public Utility Code, the General Assembly authorized the Commission to permit the implementation of alternative rate mechanisms notwithstanding other provisions of law.⁸³
99. In its declaration of policy, the General Assembly identified that the purpose of alternative rate mechanisms is to (1) create new opportunities for customers through innovations in utility operations and information technologies and (2) encourage and sustain investment through cost-recovery mechanisms enhancing safety and reliability of infrastructure “consistent with the efficient consumption of utility service.”⁸⁴
100. Among the permitted forms of alternative rate mechanisms, the General Assembly identified decoupling mechanisms, performance-based rates, formula rates, and multiyear rate plans as the type of mechanisms for the Commission to consider.⁸⁵
101. Rates must still be just and reasonable under the proposed alternative rate mechanism.⁸⁶
102. The utility is still required to satisfy its burden of proof that the proposed alternative rate mechanism will result in just and reasonable rates.⁸⁷
103. The Commission’s decision must be based on substantial evidence found in the record before it and not in the consideration of other rate mechanisms approved in Pennsylvania or neighboring jurisdictions.⁸⁸
104. The adoption of a similar alternative rate mechanism by a utility pursuant to a settlement agreement should not be considered to be evidence or precedential for

⁸³ 66 Pa. C.S. § 1330.

⁸⁴ 66 Pa. C.S. § 1330(a).

⁸⁵ 66 Pa. C.S. § 1330(b).

⁸⁶ 66 Pa. C.S. § 1301.

⁸⁷ 66 Pa. C.S. § 315(a), 332(a).

⁸⁸ 2 Pa. C.S. § 704.

purposes of assessing the alternative rate mechanism placed before the Commission.⁸⁹

A. Weather Normalization Adjustment

105. The Commission has the authority and discretion to permit alternative ratemaking where it will produce just and reasonable and non-discriminatory rates.⁹⁰
106. The Commission has the authority and discretion to permit alternative ratemaking where it will enhance the safety, security, reliability, or availability of utility infrastructure and is consistent with efficient consumption of utility service.⁹¹
107. Administrative agencies are not bound by the rule of *stare decisis* and may render inconsistent opinions that may overrule or distinguish prior opinions.⁹²
108. Utilities are not entitled to assurance during ratemaking that they will be able to recover net revenues; instead, utilities are granted the opportunity to recover their authorized revenue increase, and the public interest weighs against guaranteeing particular levels of revenue.⁹³
109. In the only fully litigated rate proceeding involving a utility's request for a permanent WNA, the Commission determined that the proposed WNA would not result in just and reasonable rates.⁹⁴
110. Columbia has not met its burden of proving the WNA will enhance the safety, security, reliability, or availability of utility infrastructure and is consistent with efficient consumption of utility service.⁹⁵
111. Substantial record evidence demonstrates that the proposed WNA will harm customers generally and disproportionately harm low-income customers.
112. Substantial record evidence demonstrates that the proposed WNA will harm customers' incentives to conserve energy or invest in energy efficiency improvements.

⁸⁹ *HIKO Energy, LLC v. Pa. PUC*, 163 A.3d 1079, 1102-03 (Pa. Cmwlth. 2017) *aff'd* by *HIKO Energy, LLC v. Pa. PUC*, 209 A.3d 246, 255 (Pa. 2019); *Bell Atl. – Pa., Inc. v. Pa. PUC*, 672 A.2d 352, 354 (Pa. Cmwlth. 1995).

⁹⁰ 66 Pa.C.S. §§ 1330, 1301, 1304.

⁹¹ 66 Pa.C.S. § 1330(a)(2).

⁹² *Bell Atl. – Pa., Inc. v. Pa. PUC*, 672 A.2d 352, 354 (Pa. Cmwlth. Dec. 18, 1995).

⁹³ *Hope* at 603; *Pa. Elec. Co. v. Pa. PUC*, 502 A.2d 130, 133-35 (Pa. 1985).

⁹⁴ *Pa. PUC v. PECO Energy Company – Gas Division*, Docket No. R-2024-3046932 (Order entered Dec. 12, 2024) (*PECO Gas 2024*) at 94-101.

⁹⁵ 66 Pa.C.S. § 1330(a)(2).

- 113. Substantial record evidence demonstrates that the proposed WNA will harm customers generally and disproportionately harm low-income customers.
- 114. Columbia has not met its burden of proving that its proposed WNA will produce just and reasonable rates.
- 115. Columbia's proposed WNA is denied.

B. Revenue Normalization Adjustment

- 116. The Commission specifically rejected the revenue decoupling mechanism proposed by Pennsylvania-American Water Company (PAWC) in its 2023 rate case.⁹⁶
- 117. In *Columbia 2020*, the Commission adopted the ALJs' determination "that Columbia failed to prove the RNA Rider is needed and reasonable, or that the RNA Rider will result in rates that are just, reasonable and in the public interest. Further, the Company did not show its current rates and systems of revenue streams will fail to provide revenue stability."⁹⁷
- 118. Columbia did not meet its burden of proof that the proposed RNA satisfies the Commission's 14 policy factors regarding whether a proposed alternative rate mechanism would result in just and reasonable rates.
- 119. Under the proposed RNA, Columbia's captive customers would be subject to an example of the monopolistic excess against which the Commission is designed to protect against.⁹⁸
- 120. Under the proposed RNA, all costs which were charged to customers in the year prior are deemed to be "fixed" even though "fixed" is not a category of cost causation, and costs recovered through the proposed RNA as a fixed surcharge may be throughput-related, such as mains costs, and are appropriately considered to vary with usage.
- 121. Rates should be designed to allocate to future beneficiaries of a system's design and construction their fair share of their customer class's costs.⁹⁹
- 122. Columbia presented no meaningful basis to distinguish the proposed RNA from PAWC's proposed RDM, PECO Gas's proposed WNA, or Columbia's straight-fixed

⁹⁶ *PAWC 2023*.

⁹⁷ *Columbia 2020* at 264-65 (citing R.D. at 403).

⁹⁸ *Pittsburgh v. Pa. PUC*, 128 A.2d 372, 383 (Pa. Super. 1956).

⁹⁹ *PICGUG*, 2025 Pa. Cmwlt. LEXIS 133 at * 39.

variable pricing model in *Columbia 2010*, regarding incentives to conserve energy and pursue energy efficiency.¹⁰⁰

123. Columbia has not met its burden of proving the RNA will enhance the safety, security, reliability, or availability of utility infrastructure and is consistent with efficient consumption of utility service.¹⁰¹
124. The proposed RNA is not necessary for Columbia to have a reasonable opportunity to earn a return on rate base.
125. Substantial record evidence demonstrates that the proposed RNA will harm customers generally and disproportionately harm low-income customers.
126. Substantial record evidence demonstrates that the proposed RNA will harm customers' incentives to conserve energy or invest in energy efficiency improvements.
127. Substantial record evidence demonstrates that the proposed RNA will harm customers generally and disproportionately harm low-income customers.
128. Columbia has not met its burden of proving that its proposed RNA will produce just and reasonable rates.
129. Columbia's proposed RNA is denied.

IX. Customer / Quality of Service

130. "Service" is used broadly and inclusively, and captures "any and all acts done, rendered, or performed" by public utilities.¹⁰²
131. In setting just and reasonable rates, the Commission "shall consider...the efficiency, effectiveness and adequacy of service of each utility."¹⁰³
132. The Commission can direct the adequate, reasonable, safe, sufficient service to be observed and furnished by the utility.¹⁰⁴

¹⁰⁰ *Dee-Dee Cab, Inc. v. Pa. PUC*, 817 A.2d 593, 598 (Pa. Cmwlth. 2003) (citing *Bell Atl.-Pa.*, *supra*).

¹⁰¹ 66 Pa.C.S. § 1330(a)(2).

¹⁰² 66 Pa. C.S. § 102; *West Penn Power Co. v. Pa. PUC*, 578 A.2d 75, 77 (Pa. Cmwlth. 1999).

¹⁰³ 66 Pa. C.S. § 523.

¹⁰⁴ 6 Pa. C.S. §§ 1504, 1505.

133. The Commission has recently and properly recognized that “[a] base rate proceeding ‘is the proper venue for hearing [] customer service issues.’”¹⁰⁵
134. The Commission may also condition a portion of a utility’s requested rate increase on its compliance with service adequacy objectives.¹⁰⁶
135. The burden of proof to demonstrate that a public utility’s services are adequate is on the utility; other parties are not required to demonstrate the utility services are inadequate for the Commission to decide that such is the case.¹⁰⁷
136. The OCA’s proposed improvements to Columbia’s quality of customer service are supported by substantial evidence.
137. Columbia should be required to develop and implement a root cause analysis of customer disputes, informal and formal complaints, and Bureau of Consumer Service findings, particularly those identified as “verified” and “infractions” on a regular basis to provide adequate and reasonable service.
138. Columbia should be required to revise its training materials to comply with all the applicable consumer protections and rights for residential customers facing termination of service to reflect the full range of customer rights associated with termination of service to provide adequate and reasonable service.

X. Universal Service Programs

139. Rates set in this proceeding must be just and reasonable, which requires balancing the interests of all customers, including low-income residential consumers, with the interests of the Company.¹⁰⁸
140. There are few considerations as important as affordability, as affordability “is in both the shareholder and ratepayers’ best interest. Affordable bills will maximize revenues for the Company and will enable ratepayers to continue to receive an essential service.”¹⁰⁹

¹⁰⁵ *PUC v. Phila. Gas Works*, 2023 PA. PUC LEXIS 93, Order at 193 (April 20, 2023) (PGW 2023).

¹⁰⁶ *Nat’l Utils. v. Pa PUC*, 709 A.2d 972, 977-78 (Pa. Cmlwth. Ct. 1998) (quoting *D.C. Transit System, Inc. v. Wash. Metro. Transit Comm’n*, 466 F.2d 394, 417 (D.C. Cir. 1972)).

¹⁰⁷ 66 Pa. C.S. § 315(c); *Pa. PUC v. Duquesne Light Co.*, Docket No. R-2021-3024750, Order at n. 14 (Dec. 16, 2021).

¹⁰⁸ *Pittsburgh v. Pa PUC*, 126 A.2d 777, 794-85 (Pa. Super Ct. 1956).

¹⁰⁹ *Pa. PUC v. Roaring Creek Water Co.*, 73 Pa. PUC 373, 400 (1990) (*Roaring Creek 1990*).

141. The Public Utility Code “seeks to ensure that service remains available to all customers on reasonable terms and conditions.”¹¹⁰
142. NGDCs, specifically, are required to assist low-income customers with affording their natural gas service.¹¹¹
143. The Commission should consider the effect of a rate increase on the utility’s customers’ ability to afford the rate increase when determining an appropriate return on equity for ratemaking purposes.
144. Pennsylvania regulations provide that income eligible applicants – not customers but applicants – are exempt from being required to post cash security deposits.¹¹²
145. The OCA supported its recommended improvements to Columbia’s universal service programs with substantial evidence.
146. Columbia should be required to develop and implement a screening process at the time a household first applies to receive service from Columbia to determine whether the applicant: (1) should be classified as a Confirmed Low-Income customer; and (2) should be referred to the CAP application process to provide reasonable and adequate service.
147. Columbia should be required to modify any policies, practices, standard operating procedures, or other internal activities so as to fully communicate in a clear and timely manner the fact of that low-income deposit exemption to new applicants to provide reasonable and adequate service.
148. Columbia met its burden of proof with respect to the proposed implementation of the CAP arrearage forgiveness pilot program.

XI. Energy Efficiency Program

149. Columbia met its burden of proof with respect to the proposed implementation of Phase II of the Energy Efficiency Plan.

XII. Tariff Issues (Not Addressed Above)

150. Columbia has failed to meet its burden of proof that the proposed Economic Development Distribution Service Rate tariff should be implemented.

¹¹⁰ 66 Pa. C.S. § 1402(3).

¹¹¹ 66 Pa. C.S. § 2203(7)

¹¹² 52 Pa. Code § 56.32(e).

151. Columbia has failed to meet its burden of proof that it should be permitted to amend its tariff to expand the data provided on its customers to undisclosed third-parties.

OCA Proposed Ordering Paragraphs

It is hereby ORDERED THAT:

1. Columbia Gas of Pennsylvania, Inc. shall not place into effect the rates, rules, and regulations contained in Supplement No. 392 to Tariff Gas Pa. P.U.C. No. 9, which have been found to be unjust, unreasonable and, therefore, unlawful.
2. Columbia Gas of Pennsylvania, Inc. is authorized to file tariffs, tariff supplement, or tariff revisions containing rates designed to produce no less than an annual base rate decrease of \$36,316,933.
3. Columbia Gas of Pennsylvania, Inc. shall file detailed calculations with its tariff filing, which shall demonstrate to this Commission's satisfaction that the filed rates comply with the proof of revenue, in the form and manner customarily filed in support of compliance tariffs.
4. The request of Columbia Gas of Pennsylvania, Inc. to implement a Weather Normalization Adjustment is denied.
5. The request of Columbia Gas of Pennsylvania, Inc. to implement a Revenue Normalization Adjustment is denied.
6. Columbia Gas of Pennsylvania, Inc. shall develop and implement a root cause analysis of customer disputes, informal and formal complaints, and Bureau of Consumer Service findings, particularly those identified as "verified" and "infractions" on a regular basis. The analysis should be developed in consultation with stakeholders within six months of the adoption of the final order in this proceeding.
7. Columbia Gas of Pennsylvania, Inc. shall revise its training materials to comply with all the applicable consumer protections and rights for residential customers facing termination of service to reflect the full range of customer rights associated with termination of service. The revision should be developed in consultation with stakeholders within six months of the adoption of the final order in this proceeding.
8. Columbia Gas of Pennsylvania, Inc. shall develop and implement screening process at the time a household first applies to receive service from Columbia to determine whether the applicant: (1) should be classified as a Confirmed Low-Income customer; and (2) should be referred to the CAP application process within six months of the adoption of the final order in this proceeding.
9. Columbia Gas of Pennsylvania, Inc. shall modify any policies, practices, standard operating procedures, or other internal activities so as to fully communicate in a

clear and timely manner the fact of that low-income deposit exemption to new applicants within 60 days of the adoption of the final order in this proceeding.

10. Columbia Gas of Pennsylvania, Inc. is permitted to implement the CAP arrearage forgiveness pilot.
11. Columbia Gas of Pennsylvania, Inc. is permitted to implement Phase II of the Energy Efficiency Plan, as modified by the Office of Consumer Advocate.
12. Columbia Gas of Pennsylvania, Inc. shall develop and file at this docket number a compliance filing no later than six months after a final order is entered in this proceeding indicating compliance with this Order.
13. The request of Columbia Gas of Pennsylvania, Inc. to implement the proposed Economic Development Distribution Service Rate tariff is denied.
14. Columbia Gas of Pennsylvania, Inc. shall comply with all directives, conclusions and recommendations contained in this Commission's Opinion and Order that are not the subject of individual ordering paragraphs as fully as if they were the subject of specific ordering paragraphs.
15. The Complaints filed by the various parties to this proceeding at Docket Number R-2025-3053499 are granted in part and denied in part, to the extent consistent with this Commission's Opinion and Order.

DATE: _____

Jeffrey A. Watson
Chad Allensworth
Administrative Law Judges

APPENDIX C

**INVENTORY OF TESTIMONY AND EXHIBITS SUBMITTED BY THE OFFICE
OF CONSUMER ADVOCATE AND ADMITTED TO THE RECORD**

DIRECT TESTIMONY

- OCA Statement 1: Direct Testimony of Michael Deupree consisting of 62 pages of testimony, Appendix A consisting of 5 pages, and Exhibits MWD-1 through MWD-11 along with a signed verification of Michael Deupree.
- OCA Statement 2: Confidential Version of Direct Testimony of Dante Mugrace consisting of 48 pages of testimony, Appendix A consisting of 24 pages, and Exhibits DM-1 through DM-34 along with a signed verification of Dante Mugrace.
- OCA Statement 2: Public Version of Direct Testimony of Dante Mugrace consisting of 48 pages of testimony, Appendix A consisting of 24 pages, and Exhibits DM-1 through DM-34 along with a signed verification of Dante Mugrace.
- OCA Statement 3: Direct Testimony of David J. Garrett consisting of 69 pages of testimony, Appendices A through E and Exhibits DJG-1 through DJG-24 with a signed verification of David J. Garrett.
- OCA Statement 4: Direct Testimony of Jerome D. Mierzwa consisting of 17 pages of testimony and a signed verification of Jerome D. Mierzwa.
- OCA Statement 5: Direct Testimony of Roger Colton consisting of 119 pages of testimony and Exhibits RDC-1 through RDC-3 with a signed verification of Roger Colton.
- OCA Statement 6: Confidential Version of Direct Testimony of Barbara R. Alexander consisting of 26 pages of testimony and Exhibits BA-1 through BA-7 with a signed verification of Barbara R. Alexander.
- OCA Statement 6: Public Version of Direct Testimony of Barbara R. Alexander consisting of 26 pages of testimony and Exhibits BA-1 through BA-7 with a signed verification of Barbara R. Alexander.

OCA Statement 7: Direct Testimony of Stacy L. Sherwood consisting of 14 pages of testimony and Attachment A with a signed verification of Stacy L. Sherwood.

REBUTTAL TESTIMONY

OCA Statement 4R: Rebuttal Testimony of Jerome D. Mierzwa consisting of 11 pages of testimony and Exhibit JDM-1R with a signed verification of Jerome D. Mierzwa.

SURREBUTTAL TESTIMONY

OCA Statement 1SR: Surrebuttal Testimony of Michael Deupree consisting of 18 pages of testimony along with a signed verification of Michael Deupree.

OCA Statement 2SR: Surrebuttal Testimony of Dante Mugrace consisting of 27 pages of testimony and Exhibits DM-SR-1 through DM-SR-34 along with a signed verification of Dante Mugrace.

OCA Statement 3SR: Surrebuttal Testimony of David J. Garrett consisting of 15 pages of testimony with a signed verification of David J. Garrett.

OCA Statement 4SR: Surrebuttal Testimony of Jerome D. Mierzwa consisting of 12 pages of testimony with a signed verification of Jerome D. Mierzwa.

OCA Statement 5SR: Surrebuttal Testimony of Roger Colton consisting of 26 pages of testimony with a signed verification of Roger Colton.

OCA Statement 6SR: Surrebuttal Testimony of Barbara R. Alexander consisting of 17 pages of testimony with a signed verification of Barbara R. Alexander.

OCA Statement 7SR: Surrebuttal Testimony of Stacy L. Sherwood consisting of 6 pages of testimony with a signed verification of Stacy L. Sherwood.

ADDITIONAL EVIDENCE

OCA Cross Exh. 1: Excerpts of Prepared Direct Testimony of John J. Spanos and Associated Exhibits on Behalf of Columbia Gas of Kentucky, Inc., Case No. 2024-00092, Submitted May 16, 2024.

- OCA Cross Exh. 2: Excerpts of Prepared Direct Testimony of John J. Spanos and Associated Exhibits on Behalf of Columbia Gas of Maryland, Inc., Case No. 9701, Submitted May 12, 2023.
- OCA Cross Exh. 4: Excerpts of Prepared Direct Testimony of John J. Spanos and Associated Exhibits on Behalf of Columbia Gas of Virginia, Inc., Case No. PUR-2024-00030, Submitted April 29, 2024.
- OCA Cross Exh. 5: Excerpts of Prepared Direct Testimony of John J. Spanos and Associated Exhibits on Behalf of Columbia Gas of Ohio, Inc., Case Nos. 21-637-GA-AIR, 21-638-GA-ALT, 21-639-GA-UNC, 21-640-GA-AAM, Submitted July 14, 2023.

APPENDIX D



KeyCite Yellow Flag

Reconsideration Granted by [In Matter of Application of Minnegasco, a Div. of Arkla, Inc.](#), Minn.P.U.C., May 28, 1993

1993 WL 312274 (Minn.P.U.C.), 143 P.U.R.4th 416

Re Minnegasco, Inc.

Docket No. G-008/GR-92-400

Minnesota Public Utilities Commission

May 3, 1993

Before Storm (dissenting), chairman, and Burton (dissenting), Kitlinski, Knaak, and McKanna, commissioners.

BY THE COMMISSION:

PROCEDURAL HISTORY

I. INITIAL PROCEEDINGS

***1** On July 2, 1992, Minnegasco, a Division of Arkla, Inc. (Minnegasco or the Company), filed a petition seeking a rate increase of \$24,822,800 or approximately 5.5 percent over existing rates. The Company filed its direct testimony in support of this increase as part of its rate case filing.

On August 17, 1992, the Commission issued Orders accepting the Company's filing, suspended the proposed rates, and set the matter for contested case hearing. The Office of Administrative Hearings assigned Administrative Law Judge Richard Luis to the case.

On August 27, 1992, the Administrative Law Judge (ALJ) convened a prehearing conference.

On August 31, 1992, the Commission issued its ORDER SETTING INTERIM RATES, authorizing an interim rate increase of \$11.8 million or 2.6 percent, effective September 1, 1992.

On September 14, 1992, Minnegasco made a supplemental filing of additional direct testimony and exhibits concerning the Weather Normalization Adjustment (WNA) and Financial Accounting Standard (FAS) 106.

On September 17, 1992, the ALJ issued a Prehearing Order granting the Petitions to Intervene of the Minnesota Department of Public Service (the Department), the Residential Utilities Division of the Office of the Attorney General (RUD-OAG), Honeymead Products Company (Honeymead), Minnesota Energy Consumers (MEC), Northern Natural Gas Company (Northern), and the Suburban Rate Authority (SRA). The ALJ's Order also established the hearing schedule and procedural guidelines governing the conduct of the case.

On October 26, 1992, the Department, RUD-OAG, MEC and SRA filed their direct testimony.

On November 10, 1992, the Commission issued an Order granting Minnegasco's motion to enlarge the time to object to Gas, Inc.'s petition to intervene and denying Gas, Inc.'s petition.

On or about November 20, 1992, the parties filed Rebuttal Testimony and on December 2, 1992 they filed Surrebuttal Testimony.

II. PARTIES AND REPRESENTATIVES

A. Intervenor

The intervenors and their representatives in this matter are as follows:

Minnesota Department of Public Service (the Department) represented by Scott Wilensky and Mark Chalfant, Special Assistant Attorneys General, 1100 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101;

Residential Utilities Division of the Office of the Attorney General (RUD-OAG) represented by Gary R. Cunningham, Special Assistant Attorney General, 340 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101;

Honeymead Products Company (Honeymead) represented by Rebecca J. Heltzer, McGrann, Shea, Franzen, Carnival, Straughn & Lamb, 1700 Lincoln Center, 333 South 7th Street, Minneapolis, Minnesota 55402-2436;

Minnesota Energy Consumers (MEC) represented by James J. Bertrand, Leonard, Street & Deinard, 50 South 5th Street, Suite 2300, Minneapolis, Minnesota 55402-2436;

Northern Natural Gas Company (Northern) represented by Patrick J. Joyce, P.O. Box 3330, Omaha, Nebraska 68102-0330; and

*2 Suburban Rate Authority (SRA) represented by James M. Strommen, Holmes & Graven, 470 Pillsbury Center, Minneapolis, Minnesota 55402.

B. The Company

Minnegasco was represented by Brenda Bjorklund, Miggie E. Cramblit, and John C. Sprangers, 201 South Seventh Street, Minneapolis, Minnesota 55402, Sally A. Johnson, Faegre & Benson, 2200 Norwest Center, 90 South Seventh Street, Minneapolis, Minnesota 55402-3901, and Paul T. Ruxin, Jones, Day, Reavis & Pogue, 901 Lakeside Avenue, Cleveland, Ohio 44114.

III. PUBLIC HEARINGS AND PUBLIC TESTIMONY

The ALJ held public hearings to receive comments and questions from non-intervening ratepayers. The dates and locations of these hearings are listed below:

November 10, 1992 Minneapolis

November 10, 1992 Bloomington

November 18, 1992 Mankato

November 19, 1992 Willmar

In Minneapolis, 30 persons attended and four spoke. The four speakers addressed, in turn, their concerns regarding Minnegasco's rate structure, interruptible service, service contracts, and the delivery rate on gas purchased by the customer from a third party.

In Bloomington, of the 19 persons attending, three spoke. The first speaker questioned Minnegasco's rate increase in light of reductions in the cost of gas since 1983, criticized Minnegasco's billing practices, and objected to BTU billing. The second speaker questioned Minnegasco's willingness to invest in storage gas if it wasn't allowed a return on that investment. The

third speaker requested clarification regarding Minnegasco's distribution and fixed costs and opposed the increase in rates and monthly customer fee in light of declining real incomes.

In Mankato and Willmar, 15 and 10 persons attended, respectively, but none spoke. In addition, the Commission received several dozen written comments from affected ratepayers. Generally, the commentators opposed any rate increase, especially on low income or fixed income persons. The comments stressed the pressure of increasing the cost of a basic necessity of life.

IV. EVIDENTIARY HEARINGS

The ALJ held evidentiary hearings on December 8-11, 14-16, 18, and 21, 1992 in St. Paul, Minnesota.

V. PROCEEDINGS BEFORE THE COMMISSION

On December 4, 1992, four of the parties (Minnegasco, the Department, RUD-OAG, and the SRA) filed with the ALJ an Offer of Partial Settlement.

On December 31, 1992, the ALJ issued an Order submitting the proposed Settlement to the Commission to determine whether the Settlement was in the public interest and supported by substantial evidence in the record. The ALJ stated that he found the Offer of Partial Settlement to be reasonable and supported by substantial evidence. The ALJ recommended that the Commission accept the Offer of Partial Settlement as resolving the financial and rate design issues encompassed therein.

On December 30, 1992, the same parties filed with the ALJ an Amended Offer of Partial Settlement. The Amended Settlement included agreements reached by the parties on additional issues since the start of the evidentiary hearing on December 8, 1992 and made certain clerical and computational changes.

***3** On January 29, 1993, the ALJ issued an Order submitting the proposed Amended Offer of Partial Settlement (Settlement) to the Commission to determine whether the Settlement was in the public interest and supported by substantial evidence in the record. The ALJ stated that he found the Settlement to be reasonable and supported by substantial evidence. The ALJ recommended that the Commission accept the Settlement as resolving the financial and rate design issues encompassed therein.

On February 19, 1993, the Commission met to deliberate upon the matter and decided to accept the Amended Offer of Partial Settlement in its entirety.

On March 8, 1993, the ALJ filed his final report and recommendations regarding the remaining contested issues.

On March 19, 1993, the Commission met on its own motion to reopen deliberations regarding its February 19, 1993 decision to accept the Offer of Partial Settlement. After further deliberations, the Commission left its acceptance of the Settlement unchanged.

On March 31, 1993, the Commission heard oral arguments from the parties and on April 1 and 2, 1993 the Commission met to deliberate this matter.

Upon review of the entire record of this proceeding, the Commission makes the following Findings of Fact, Conclusions of Law, and Order.

FINDINGS AND CONCLUSIONS

VI. JURISDICTION

The Commission has general jurisdiction over the Company under [Minn. Stat. §§ 216B.01 and 216B.02 \(1992\)](#). The Commission has specific jurisdiction over rate changes under [Minn. Stat. § 216B.16 \(1992\)](#).

The case was properly referred to the Office of Administrative Hearings under [Minn. Stat. §§ 14.48-14.62 \(1992\)](#) and [Minn. Rules, Part 1400.0200 et seq.](#)

VII. FURTHER ADMINISTRATIVE REVIEW

Under [Minn. Rules, Part 7830.4100](#), any petition for rehearing, reconsideration, or other post-decision relief must be filed within 20 days of the date of the Order. Such petitions must be filed with the Executive Secretary of the Commission, must specifically set forth the grounds relied upon and errors claimed, and must be served on all parties. The filing should include an original, 13 copies, and proof of service on all parties.

Adverse parties have ten days from the date of service of the petition to file answers. Answers must be filed with the Executive Secretary of the Commission and must include an original, 13 copies, and proof of service on all parties. Replies are not permitted.

The Commission, in its discretion, may grant oral argument on the petition or decide the petition without oral argument.

Under [Minn. Stat. § 216B.27, subd. 3 \(1992\)](#), no Order of the Commission shall become effective while a petition for rehearing is pending or until either of the following: ten days after the petition for rehearing is denied or ten days after the Commission has announced its final determination on rehearing, unless the Commission otherwise orders.

*4 Any petition for rehearing not granted within 20 days of filing is deemed denied. [Minn. Stat. § 216B.27, subd. 4 \(1992\)](#).

VIII. MINNEGASCO

Minnegasco is an operating division of Arkla, Inc. and maintains its principal office in Minneapolis, Minnesota. At the beginning of this matter, Minnegasco distributed natural gas at retail to customers in three states: Nebraska, South Dakota, and Minnesota. During the hearing, Minnegasco announced its plans to sell its Nebraska properties and trade its South Dakota properties for additional Minnesota properties.¹ At the end of 1991, the Company had approximately 499,539 customers in Minnesota, and an annual throughput of approximately 123 billion cubic feet. The largest metropolitan areas served are Minneapolis and the West Metro suburbs. Additionally, the Company has a significant large volume load.

IX. BURDEN OF PROOF

[Minn. Stat. § 216B.16, subd. 4 \(1992\)](#) states: “The burden of proof to show that the rate change is just and reasonable shall be upon the public utility seeking the change.”

The Minnesota Supreme Court has articulated standards for the burden of proof in rate cases. *In the Matter of the Petition of Northern States Power Company for Authority to Change Its Schedule of Rates for Electric Service in Minnesota*, 416 N.W. 2d 719 (Minn. 1987). In the *States Power* case, the Court divided the ratemaking function of the Commission into quasi-judicial and legislative aspects. The Commission acts in a quasi-judicial mode when it determines the validity of facts presented. Just as in a civil case, the burden of proof is on the utility to prove the facts by a fair preponderance of the evidence. Such items as claimed costs or other financial data are facts which the utility must prove by a fair preponderance of the evidence.

The Commission acts in a legislative mode when it weighs the facts presented and determines if proposed rates are just and reasonable. Acting legislatively, the Commission draws inferences and conclusions from proven facts to determine if the conclusion sought by the utility is justified. The Commission weighs the facts in light of its statutory responsibility to enforce the state's public policy that retail consumers of utility services shall be furnished such services at reasonable rates. In its legislative capacity, the Commission forms determinations such as the usefulness of a claimed item, the prudence of company decisions, and the overall reasonableness of proposed rates.

*5 The utility therefore faces a two part burden of proof in a rate case. When presenting its case in the rate change proceeding, the utility has the burden to prove its facts by a fair preponderance of the evidence. The utility also has the burden to prove, by means of a process in which the Commission uses its judgment to draw inferences and conclusions from proven facts, that the proposed rates are just and reasonable.

X. TEST YEAR

Minnegasco used the period July 1, 1992 through June 30, 1993 for its test year. Accordingly, the financial data submitted by the Company was largely projected. No party objected to the Company's test year period. Minnegasco's test year was used but not specifically addressed in the Offer of Partial Settlement or in the ALJ's report.

The Commission finds that the Company's use of a twelve-month test year ending June 30, 1993 was appropriate in this proceeding.

XI. OFFER OF PARTIAL SETTLEMENT ACCEPTED AND ADOPTED

The Commission finds that the Amended Offer of Partial Settlement (the Settlement) is supported by substantial evidence, promotes the public interest, and (in conjunction with the resolution of the remaining contested issues in this Order) will result in just and reasonable rates. The Commission will accept and adopt the Settlement.² A copy of the Settlement is incorporated into this Order by reference. The non-proprietary version of the Settlement is attached to this Order.

A Stipulation of Facts accompanied the Settlement. The parties set forth the evidentiary basis for their resolutions of individual issues and explained their basis in reason and policy. In addition, the parties made their witnesses available for questioning by Commission staff to clarify the evidentiary basis for Settlement positions if necessary. Since the Commission must base its rate case decisions on the record, this increased the Settlement's value and credibility. [Minn. Stat. § 14.60, subd. 2 \(1992\)](#). While the Commission could have approved the Settlement based solely on its independent review of the record, it is reassuring that the parties demonstrated that the record was central to their negotiations on every issue.

In non-ratemaking settlement negotiations it is common for parties to concede some issues to obtain a more favorable resolution of others they value more highly. This is reasonable and appropriate in private disputes, where the goal of the settlement process is to reach a result satisfactory to all parties. In Commission proceedings, however, the Commission's responsibility is to serve the public interest. This fundamental responsibility does not change when considering the proposed settlement of a rate case. The Commission certainly considers the monetary and administrative efficiency benefits of not subjecting settled issues to a fully contested case treatment. However, the Commission also scrutinizes a proposed settlement to see whether it protects the interests of the Company, the public, and all customer classes. To assure that this objective is achieved, the Commission examines to see that every issue is resolved within the bounds of acceptable regulatory practice. This is particularly important in rate case settlements because resolution of individual issues not only affects rate levels and structures adopted in this proceeding but has implications on future rate levels and rate structures.

***6** The Commission is convinced that the Settlement proposed in this matter meets that standard. Each issue addressed in the Settlement has been resolved within the established parameters of acceptable regulatory practice. Accordingly, the Commission will accept the Settlement.

This is not to say that if the Commission had considered the issues resolved in the Settlement on the merits in a contested context the Commission would have decided these issues the same way that they were settled. The Commission has serious concerns regarding a number of the settled issues, including Minnegasco's capital structure, incentive plan costs, manufactured gas plant costs, and appliance service regulated/non-regulated cost allocations. The Commission notes that its acceptance of the Settlement in no way provides precedent on how it would resolve the issues contained therein in future rate cases, other than that the Settlement treatment of the issue was within the range of acceptable regulatory practice. In sum, acceptance of the Settlement does not diminish the Commission's discretion in future rate cases to choose other options that fall within the range of reasonable regulatory practice.

Additional Filing Requirements

To underscore the Commission's particular concern regarding the resolution of certain issues, the Commission will require further attention to the following issues:

1. **Definition of MGP Costs** — Minnegasco's proposed and stipulated recovery amounts for Manufactured Gas Plant cleanup costs were categorized by amounts for remediation, legal services, investigation, and amortization. Minnegasco projected amounts in these categories that totaled over \$5 million. In its compliance filing within 60 days of this Order, the Company will be required to provide further definition of these costs, including the breakdown of costs that would be internal, external, legal, consulting, contracting, and other. Utility regulatory costs, if any, shall also be shown.
2. **MGP Cost Recovery Efforts** — In its compliance filing within 60 days of this Order, the Company also will be required to provide an update of its insurance recovery activities and plans, including what claims it has filed and what efforts have been made and will be made to identify and recover from other potential parties involved.
3. **Annual Report of MGP Costs** — Minnegasco will be required to file annually a report of its MGP cleanup costs and MGP cost recoveries.
4. **Other issues** — The Commission expects that the parties will address the merits of all the settled issues in future rate cases and will require the Company, in its next rate case filing, to describe 1) the treatment of incentive compensation, vacation accrual, and winter leak surveys in the test year costs, and 2) the impact on the revenue requirement of using an industry average capital structure.

XII. REMAINING CONTESTED FINANCIAL ISSUES

A. Financial Accounting Standard 106

1. Factual Background

***7** In December of 1990 the Financial Accounting Standards Board, the professional association that sets accounting standards for American finance and business, issued a new standard on the appropriate accounting treatment of certain post-employment benefits. These benefits are known as PBOPs, for "Post-retirement Benefits Other than Pensions." The main benefit in this category is health insurance, but life insurance, dental insurance, and miscellaneous benefits are also included. The new accounting standard requires companies to account for PBOPs on an accrual basis. In the past nearly all Minnesota utilities, including Minnegasco, have recorded these expenses on a cash basis.

Under cash basis (pay-as-you-go) accounting, PBOP expenses are not recognized on a company's books until payment is made. Under accrual accounting, these expenses are recognized on a pro-rata basis during an employee's period of service, as the obligation to pay arises. In a recent all-utility proceeding, the Commission adopted Financial Accounting Standard 106 for recordkeeping and ratemaking purposes, subject to review of all expenses for prudence and reasonableness.³ The Order in that proceeding authorized Minnesota utilities to shift to accrual accounting to record future PBOP obligations as they are incurred. It also authorized utilities to use deferred accounting to record PBOP costs in excess of those that would have been recorded under cash basis accounting.

To avoid prolonged uncertainty about the rate effects of the new accounting standard, the Commission limited deferred accounting to three years. Companies were required either to secure a ratemaking determination during that time or to forfeit any ability to recover deferred amounts in rates. This general rate case is the first proceeding in which the Commission has been asked to rule on the recoverability of the costs measured using the new FASB standard.

No party challenges the accuracy of the Company's calculations of current PBOP service costs being incurred for active employees or the recovery of these costs in rates. The Commission, too, finds the current service costs of the current plan reasonable, prudent, and recoverable in rates.

The remaining issue is the recoverability of Minnegasco's "transition obligation," the unrecognized amount of accumulated PBOPs as of the Company's adoption of the new accounting standard on January 1, 1993. Amortization of the transition obligation is a significant component of the revenue deficiency claimed in this rate case. The amortization, plus associated interest, accounts for roughly \$3.4 million of the annual rate increase sought by the Company.

***8** Minnegasco has calculated its transition obligation using the formula prescribed by the Financial Accounting Standards Board (FASB). The total obligation is calculated on the basis of the cost of the Company's current PBOP plan, as required by FASB. The Company proposes to amortize the obligation over 14 years, which is acceptable under FASB guidelines. No party challenges the accuracy of the Company's calculations, which the Commission, too, accepts as accurate. The other parties do, however, challenge the reasonableness of allowing full recovery of the transition obligation and associated interest and the reasonableness of the proposed 14-year amortization period.

The Department and the RUD-OAG recommend disallowing 50 percent of the transition obligation, and associated interest, on grounds that an expense so extraordinary and unrepresentative of test year expense should be shared by ratepayers and shareholders. The SRA recommends total disallowance on grounds that the Company was imprudent in failing to adopt accrual accounting sooner. The Administrative Law Judge recommended granting recovery of the entire transition obligation and associated interest.

2. Accounting Principles Do Not Control Ratemaking

The Commission notes that costs can be treated differently for accounting and ratemaking purposes. As the Minnesota Supreme Court has explained,

Nothing in the federal regulations or the Minnesota Rules suggests that the system of accounts is determinative of the treatment of any item for purposes of setting rates or that the system deprives MPUC of its power or absolves it of the duty to decide the issues before it and to set just and reasonable rates.

Petition of Continental Telephone Company, 389 N.W.2d 910, 915 (Minn. 1986).

3. Commission Action

The Commission will allow recovery of 50 percent of the transition obligation and associated interest, establish a 20-year amortization period, and authorize internal funding, for the reasons set forth below.

a. The Transition Obligation is an Out-of-Test-Year Expense

In every general rate case, the Commission bases rates on a representative slice of the utility's normal operations called the "test year." The main purpose of the test year is to ensure that rates are based on facts and experience instead of conjecture. It is also intended to replace the fiscal discipline of the marketplace, which is absent for monopolies, with the fiscal discipline of prior determination of reasonable costs. Finally, and most significantly in this case, it is intended to ensure as much precision as possible in matching the time a cost is incurred with the time it is recovered from ratepayers.

This final goal, matching the time a cost is incurred with the time it is recovered, is one of the most important functions of regulation. Since utility service is a public necessity provided in a monopoly environment, rates must be set to recover the full cost of providing service while they are in effect. Placing any portion of the cost of service on preceding or succeeding ratepayers raises grave issues of fairness, as well as resource allocation. As a general rule, it is inequitable and economically unsound to ask one "generation" of captive ratepayers to bear the cost of providing service to another.

*9 Second, matching the time that costs are incurred to the time that they are recovered protects the integrity of the ratemaking process by ensuring that only representative, not aberrant, costs are included in rates. Regulatory commissions assume that actual costs will vary slightly from test year costs. Under normal circumstances, however, utilities are expected to place their costs in test year categories or bear them themselves. The Commission does not normally adjust test year costs to reflect non-test year expenses. As the Commission explained in an earlier Order:

... the test year method by which rates are set rests on the assumption that changes in the Company's financial status during the test year will be roughly symmetrical — some favoring the Company, others not. Not adjusting for either type of change maintains this symmetry and maintains the integrity of the test year process. Anomalies are likely to exist in and beyond any test year.

In the Matter of the Petition of Minnesota Power & Light Company, d/b/a Minnesota Power, for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota, Docket No. E-015/GR-87-223 ORDER AFTER RECONSIDERATION AND REHEARING (May 16, 1988).

Finally, utilities do not face the same pressure as unregulated enterprises to monitor costs precisely and continuously. The test year, and the time matching it forces, are valuable tools for ensuring that costs are promptly and properly identified, recognized, and recovered. In short, the test year is an important regulatory safeguard against under-recovery, over-recovery, and imprecision in ratemaking.

Since the transition obligation is an accounting adjustment for obligations incurred but not recognized in the past, it is an out-of-test-year expense that would normally be disallowed. The Commission believes there are sound reasons for allowing part of it in this case, however.

b. Partial Recovery of the Transition Obligation is Equitable

First of all, the costs represented in the transition obligation are costs whose recovery has been allowed in past ratemakings under cash basis accounting. Furthermore, in recording these expenses on a cash basis in the past, Minnegasco was following established accounting and regulatory practice. To disallow them entirely now because of a change in generally accepted accounting principles would be unduly harsh.

At the same time, however, placing the entire transition obligation in rates would be less than equitable. Although the ratepayers are now paying retirees' PBOPs under cash basis accounting, converting both retirees' and current employees' PBOPs to accrual accounting results in just the sort of overlap of past and current costs the test year concept is designed to avoid. It results in one group of ratepayers bearing expenses that would have been charged to another group, given perfect information earlier. Furthermore, the financial burden of the accounting change is substantial, increasing annual PBOP expense by some 350 percent. Placing the entire burden on ratepayers, then, cannot be done lightly.

***10** Finally, although the new accounting standard benefits all stakeholders by enhancing the accuracy of corporate financial statements, it benefits investors so significantly that apportioning part of the transition cost to them is reasonable. It is the investment community, after all, who has the greatest interest in the financial condition and prospects of individual companies, and the greatest need to make valid comparisons between them. It is these needs FAS 106 was designed to meet. Of course, ratepayers also benefit from meaningful financial disclosure and the confidence it produces in investors. Under these circumstances, the Commission concludes allowing recovery of 50 percent of the transition adjustment in rates is reasonable.

It is also consistent with Commission action in other cases involving extraordinary expenses that do not fit within established rate case categories. In such cases the Commission has not considered itself bound to allow or disallow the expenses in their entirety, but has instead sought creative and judicious regulatory treatment. See, for example, the decision in Minnesota Power's 1987 rate case partially disallowing the costs of maintaining excess capacity⁴ and the decision in NSP's 1986 rate case apportioning manufactured gas plant clean up costs between ratepayers and shareholders.⁵

Other regulatory bodies have taken similar approaches. The Illinois Commerce Commission, for example, has determined that coal tar clean up costs should be apportioned equally between ratepayers and shareholders.⁶ The Vermont Public Service Board has found that the costs of a management incentive plan should be allocated equally between ratepayers and shareholders. *In Re Green Mountain Power Corporation*, 119 PUR4th 62 (Vermont Public Service Board 1991).

c. Full Recovery of the Transition Obligation Not Required for Investor Confidence

The Commission rejects the Company's claim that failure to include the entire transition obligation in rates is likely to adversely affect investors' perception of the Minnesota regulatory environment and drive up the Company's cost of capital. The Commission believes that this Order speaks for itself and will be properly interpreted by the investment community. The Commission has consistently included, and will continue to include, all allowable costs in rates. The Commission will continue to seek innovative and equitable approaches to costs, such as the transition obligation, that do not qualify for automatic inclusion in rates.

d. Total Disallowance Not Required for Failure to Adopt Accrual Accounting Sooner

***11** The Suburban Rate Authority (SRA) argued that the entire transition obligation should be disallowed because the Financial Accounting Standards Board had indicated as early as 1979 that it was rethinking its position allowing cash basis accounting for PBOPs. The SRA contended the prudent course would have been to seek Commission approval to implement accrual accounting earlier.

The Commission agrees with and adopts Findings 46 and 53 of the Administrative Law Judge rejecting this claim. It was prevailing business practice, and the preferred practice under generally accepted accounting principles, to record PBOPs using cash accounting. The Commission believes the Company acted prudently in waiting for the new accounting standard to be issued before converting to accrual accounting.

e. External Funding of PBOPs Unnecessary

The Company proposed that it be allowed to fund its PBOP obligation internally, arguing that its strong equity position made external funding unnecessary and that its inability to use tax-deductible funding vehicles made it counterproductive. No party opposed internal funding, and the Administrative Law Judge recommended it.

The Commission agrees that internal funding offers adequate security and clear cost advantages at present. The Commission will require the Company to file an annual report with the Department of Public Service, however, detailing amounts accrued in the internal fund, amounts expended, projected future accruals and expenditures, the feasibility of alternative funding options (including tax-deductible funding options), and Company equity levels. This report will allow continuous monitoring of the internal fund and prompt identification of any conditions warranting re-examination of external funding.

f. 50 Percent of the Interest on the Transition Obligation Allowed

The Company seeks recovery of both the transition obligation and associated interest. The transition obligation consists of unrecognized PBOP obligations, reduced to present value. Interest on those obligations for the time between accrual and payment is necessary if the goal is to make the Company whole. The Administrative Law Judge found that interest on the transition obligation should be allowed to the same extent as the transition obligation itself. Finding No. 47. The Commission accepts and adopts that recommendation, believing it would be anomalous to allow recovery of interest on principal that has been disallowed.

g. Twenty Year Amortization Period Established

Under FAS 106 Minnegasco can recognize the total transition obligation immediately, amortize it over the average remaining service period of active participants in its PBOP plan, or amortize it over 20 years. The Company proposed a 14-year amortization period, based on the remaining service period of active plan participants, for ratemaking purposes. (The Company stated it had not yet determined whether to amortize the transition obligation or recognize it immediately for financial reporting purposes.) The Department proposed a 16-year period, based on the weighted average remaining lives of active and inactive plan participants. The RUD-OAG recommended a 20 year amortization; the SRA recommended a 40-year period.

***12** The Commission agrees with the Administrative Law Judge that a 20-year amortization period represents the best balance between shareholder and ratepayer interests. It eliminates the mismatch between the times costs are incurred and recognized within a reasonable time period and with moderate rate impact. The Financial Accounting Standards Board's acceptance of 20 year amortization periods is another indication of its basic reasonableness. The Commission accepts and adopts the Administrative Law Judge's finding (No. 43) and recommendation, and will establish a 20-year amortization period.

B. Annual Adjustment for Gas Storage Carrying Costs

Minnegasco proposed an annual true-up of carrying costs associated with gas storage inventory. The true-up would compare the carrying costs on the level of stored gas inventory included in base rates with the carrying costs on its actual month-end levels of inventory for the year purchased from Natural Gas Pipeline of America (NGPL). The difference would be included in its annual gas cost reconciliation (PGA true-up). The carrying charge would be the overall authorized rate of return.

The Company argued that gas inventory carrying costs are a direct gas cost which should be trued-up through the PGA. Minnegasco stated that in the absence of a true-up, the Company will be at risk for under-recovery and ratepayers for over-recovery of these costs. Minnegasco argued that its position is consistent with Commission precedent on carrying costs on gas storage inventory.

The Department opposed the carrying-cost true-up proposed by Minnegasco. The Department contended that stored gas should be treated no differently than any other type of inventory used to provide utility service. Inventory is included in rate base and earns a return, thus allowing Minnegasco the opportunity to recover the associated carrying cost. The Department contended that there was no reason to guarantee the Company dollar for dollar recovery of this particular cost.

The ALJ recommended adopting Minnegasco's proposal to true-up carrying costs on gas storage inventory, finding it to be reasonable and to be consistent with past Commission orders.

The Commission rejects the Company's proposal to allow an annual true-up of carrying costs on stored gas inventory. The Commission finds no compelling reason to guarantee Minnegasco dollar for dollar recovery of this particular cost. Rather, stored gas inventory should be treated like all other types of inventory that are included in rate base and earn a return.

As noted by the parties, the Commission has granted variances to its PGA rules which allowed Minnegasco, and other gas companies, to recover carrying costs associated with recent gas storage contracts through the PGA. The Commission recognized that firm contract storage was a new service that was not built into the utility's base rates and was a benefit to ratepayers. Allowing recovery through the PGA would remove disincentives for the use of storage service by removing the risk of under-recovery. However, the Commission required that the issue of gas storage carrying charges be reviewed in the companies' next rate cases and specifically recognized that it may come to view recovery of carrying costs on a test year basis rather than through PGA filings.⁷

***13** The Commission agrees with the Department that varying its PGA rules to allow Minnegasco, and other gas utilities, to include carrying charges on gas storage inventory until its next rate case was an equitable stop-gap approach for dealing with a new market environment. At that time, Minnegasco did not have storage costs related to the NGPL contract built into its base rates and thus would not have recovered carrying costs if the variance had not been granted. However, the situation has changed. In the Settlement, the parties agreed to include \$18.2 million in rate base for Gas Stored Underground - Current. This reflects gas stored in Minnegasco's Waterville, Minnesota reservoir and gas storage purchased from NGPL. The Company will be allowed an opportunity to earn its overall rate of return on this amount, the same as with any other item included in rate base for the test year.

C. Annual Adjustment for Taxes, Fees, and Permits

1991 amendments to [Minn. Stat. § 216B.241](#) gave the Commission authority to allow utilities to adjust their rates for changes in taxes, fees, and permits under certain conditions. [Minn. Stat. § 216B.241, subd. 2b](#). Recovery of expenses; taxes, provides in relevant part:

... a utility may file annually, or the public utilities commission may require the utility to file, and the commission may approve, rate schedules containing provisions for the automatic adjustment of charges for utility service in direct relation to changes in the expenses of the utility for real and personal property taxes, fees, and permits, the amounts of which the utility cannot control. A public utility is eligible to file for adjustment . . . under this subdivision only if, in the year previous to the year in which it files for adjustment, it has spent or invested at least 1.75 percent of its gross revenues from provision of electric service and .6 percent of its gross revenues from provision of gas service for that year for energy conservation improvements under this section.

Under [Minn. Stat. § 216B.241, subd. 1a](#), gas utilities are required to spend 0.5 percent of gross Minnesota operating revenues on energy conservation improvements. In order to be eligible for the adjustment for taxes, fees, and permits under subd. 2a, the gas utility must spend at least 0.6 percent.

Minnegasco proposed a Property Tax Adjustment Rider which would establish an annual adjustment for property taxes, fees, and permits, under this statute. Minnegasco proposed to file for the adjustment by March 31 of each year, to go into effect on

June 1. The filing would compare the actual annual expenditures for real and personal property taxes, permits, and fees imposed by state and local governments to the amount collected in rates, based on allowed costs in the most recent rate case. The filing would also include documentation to show that the Company had met the required conservation spending levels.

***14** Minnegasco argued that it is important to establish the adjustment rider now, before the Company has met the additional conservation spending levels. The rider will act as an incentive to encourage Minnegasco to spend more than the statutory minimum on conservation and avoid regulatory lag.

The Department opposed the Property Tax Adjustment Rider and argued that Minnegasco's request is premature. The Department noted that Minnegasco has not yet met the 0.6 percent conservation spending requirement. The Department argued that a more thorough review of the intent of the statute, the basis for authorizing such an adjustment, and the specifics of various terms need closer scrutiny to ensure consistent application. Therefore, if the statute is implemented it should be done through a rulemaking or some other generic proceeding.

The Department mentioned several policy questions that it believed should be addressed in a more generic manner. These included whether actual property tax expenses should be flowed through or just changes in tax rates; whether dollar for dollar recovery is appropriate; the effect of changes in jurisdictional allocations on tax expense; and how to define fees and permits. The Department also noted that if Minnegasco's merger with Midwest Gas is approved, its gross revenues and CIP expenses will change.

The ALJ recommended adopting the Company's proposed Property Tax Adjustment Rider. He stated that the concerns raised by the Department can be addressed in Minnegasco's compliance filing to be made when the Company achieves the required spending levels. The ALJ said that a rulemaking is not specifically required before the statute may be implemented and that a generic proceeding may not conclude before the Company reaches the required spending levels.

The Commission agrees with the Department that Minnegasco's proposal is premature and should be denied. The Company's CIP spending levels have not yet met the 0.6 percent threshold required to qualify for the automatic adjustment. If the proposed merger with Midwest Gas takes place, it may take some time to determine new annual revenue levels and to design and implement CIP programs at the required spending levels. There is therefore no clear need to act on the proposal now. Furthermore, establishing an automatic adjustment for the first time raises issues of law, policy, and implementation that were not thoroughly addressed in this proceeding. The Commission will therefore reject the Company's proposed Property Tax Adjustment Rider.

D. Lost and Unaccounted for Gas

Lost and unaccounted for (LUF) gas is the difference between gas purchased and gas sold. Minnegasco proposed that LUF gas be included in the calculation of monthly PGA's. The Department recommended that the LUF gas be recovered by adjusting the volumes in the annual PGA trueup filing. Minnegasco agreed with the Department's approach. The Commission finds that this issue is uncontested and adjusting the volumes in the annual PGA trueup is a reasonable method to recover the cost for LUF gas. The Commission approves this method of recovery for LUF gas.

XIII. DEMAND-SIDE MANAGEMENT (DSM) INCENTIVES AND CONSERVATION ISSUES

A. Energy Conservation Improvement Plan

***15** Minn. Stat. § 216B.16, subd. 1 (1992) requires utilities filing for a general rate change to include an energy conservation plan pursuant to Minn. Stat. § 216B.241 (1992). Minnegasco submitted its plan as part of its general rate case filing on July 2, 1992. Minnegasco's plan included information on the Company's strategy to expand its conservation activities into a comprehensive demand-side management plan.

The Department stated that Minnegasco's energy conservation plan complied with applicable statutes and contained the information requested by the Commission in the past. The Department recommended that the Commission accept the energy conservation plan filed by the Company.

The Commission believes the appropriate focus of a rate case conservation plan is on a utility's long-term conservation goals. Short-term projects and plans are currently reviewed by the Department in the Conservation Improvement Program (CIP) process under [Minn. Stat. § 216B.241 \(1992\)](#). The Commission finds that Minnegasco's energy conservation plan meets the requirements of the applicable statutes and addresses the long-term conservation goals of the Company. The Commission accepts the plan as filed.

B. Carrying Charge on CIP Tracker Balances

In a previous docket, the Commission authorized the establishment of a CIP tracker account for Minnegasco⁸. CIP expenditures and revenues are tracked in this account, until the balance is submitted for potential recovery or refund in the Company's next general rate case.

Minnegasco requested that it be allowed to implement a carrying charge on its CIP tracker balance in this rate case. The Company proposed that the carrying charge be applied at the Company's authorized rate of return on equity. The Company argued that setting the carrying charge at the return on equity rather than the overall return was consistent with the legislative mandate to encourage conservation.

The Department and the RUD-OAG agreed that Minnegasco should be allowed to implement a carrying charge on its CIP tracker balance. However, these parties recommended the carrying charge be set at the Company's overall rate of return, rather than the return on equity. The Department and RUD-OAG contended that a carrying charge at the overall rate of return adequately compensates the Company for the time value of money and that the carrying charge should not be used as a conservation incentive mechanism since it is tied only to spending, not to performance.

The ALJ agreed with the Department and RUD-OAG positions. He noted that in past cases, the Commission has set the carrying charge at the overall rate of return, finding that it adequately compensates utilities for the time value of money.

***16** The Commission agrees with all the parties and the ALJ that Minnegasco should be allowed a carrying charge on its CIP tracker account. In other dockets, the Commission has consistently found that application of a carrying charge to the CIP tracker account, at the utility's authorized overall rate of return, is an equitable means of adjusting the actual level of CIP expenditures to the level projected in the utility's last rate case.⁹ Allowing a carrying charge gives recognition to the time value of money to the utility and its ratepayers. If a utility spends more than is collected through the rates set in the most recent rate case, the utility is made whole. By the same token, ratepayers are made whole if they have "lent" money to the company through over-collection between rate cases. The Commission will apply the same reasoning to this docket and will allow Minnegasco to apply carrying charges to its CIP tracker account at the Company's authorized overall rate of return.

The Commission agrees with the Department, RUD-OAG, and ALJ that Minnegasco's proposal to set the carrying charge at the rate of return on equity should be rejected. As stated above, setting the carrying charge at the overall rate of return adequately recognizes the time value of money and meets the objective of making the Company and ratepayers whole for any under- or over- collection of actual CIP costs. Any further encouragement for utility investment in conservation is better left to a well-designed demand-side management (DSM) financial incentive mechanism. DSM financial incentive proposals are discussed in a subsequent section of this Order.

C. Conservation Cost Recovery Charge

A conservation cost recovery charge (CCRC) is used by most utilities to track recovery of CIP-related costs. The CCRC is calculated by dividing allowed test-year CIP expenses by allowed test-year sales units; the result represents the revenue per Mcf that will be collected in rates related to test year CIP costs. These revenues are booked to the CIP tracker. The difference between the revenues booked and the actual expenses incurred will determine the CIP tracker balance.

In response to staff questions at evidentiary hearings, Department witness Kosowski stated that the proper CCRC to use in calculating the CIP-related revenues in this case was \$0.02894/Mcf. Minnegasco agreed with this calculation. The ALJ found it to be reasonable.

The Commission notes that the CCRC can be derived from numbers agreed to in the Settlement. Test year CIP expenses of \$3,544,833 are divided by test year gas sales volumes of 122,475,162 Mcf, resulting in the CCRC of \$0.02894/Mcf noted by the parties. Therefore, the Commission finds that a CCRC of \$0.02894 is reasonable and should be used by the Company.

D. Demand-Side Management Financial Incentive

1. The Company's Request

***17** On October 18, 1991, the Commission issued its ORDER REQUIRING GAS UTILITIES TO FILE FINANCIAL INCENTIVE PROPOSALS in Docket No. G-999/CI-91-188, *In the Matter of a Summary Investigation into Financial Incentives for Encouraging Demand-Side Resource Options for Minnesota Gas Utilities*. In that Order, the Commission required all natural gas utilities (except Midwest Gas, which was already implementing a financial incentive pilot program) to file DSM financial incentive proposals. Minnegasco filed its proposal as part of this rate case.

For its DSM financial incentive, Minnegasco proposed to recover 100 percent of lost margins due to conservation from direct impact programs. The Company planned to measure lost margins by comparing pre- and post-participation usage for a participant and comparison group. Minnegasco proposed to book lost margins to its tracker account on a monthly basis.

The Company stated that the removal of disincentives was the Company's highest priority at this time. Minnegasco argued that the Commission has previously found that 100 percent recovery of lost margins is adequately tied to performance and complies with statutory criteria. In rebuttal testimony, Minnegasco stated that if the Commission were to find a bonus incentive desirable, the Company could accept adding a 10 percent bonus on lost margins if the Company exceeded its energy savings goals.

Minnegasco opposed the performance-linked recovery of lost margins proposed by the Department and RUD-OAG. The Company stated that both proposals were unreasonable because the small "carrot" (amount of potential bonus recovery) would be quickly offset by the magnitude of the "stick" (less than full recovery of lost margins if 100 percent of goals were not met). Minnegasco argued that a number of factors beyond the Company's control could affect its ability to meet its CIP goals, and thus its ability to recover lost margins.

2. Position of the Parties; Recommendation of the ALJ

The Department and the RUD-OAG both opposed Minnegasco's DSM financial incentive mechanism and instead proposed plans that would tie lost margin recovery to the achievement of energy savings goals. These parties argued that Minnegasco would be financially indifferent as to whether it achieves more or less than its projected energy savings, because it will receive 100 percent of the margin for each unit of gas sold or each unit of gas saved.

The Department proposed to tie lost margin recovery to savings goals for direct impact programs on a project by project basis. The Department incentive mechanism would allow recovery of 110 percent of lost margins if energy savings goals are exceeded; 100 percent recovery if the goals are met; 75 percent recovery if 75 to 100 percent of goals are achieved; 50 percent recovery if 35 to 75 percent of goals are met; and no recovery if less than 35 percent of goals are achieved.

***18** The RUD-OAG incentive proposal would require at least 50 percent of program savings goals to be achieved before any lost margin recovery was allowed. If 50 percent or more of goals are achieved, the proposal would allow lost margin recovery as a percentage of actual savings compared to projected savings. For example, if Minnegasco achieved 60 percent of its projected goal, the Company would receive 60 percent of its lost margins. Recovery would be capped at 1.2 times savings, allowing a maximum bonus of 20 percent of lost margins.

The Department and the RUD-OAG recommended approval of Minnegasco's method for measuring lost margins, with the modification that CIP participants be excluded from the comparison group to provide a greater accuracy of measurement.

The Department and RUD-OAG argued that lost margins should be booked to the tracker annually, after the Commission has approved the energy savings achieved. These parties recommended that Minnegasco file its calculation of lost margins and incentives to be included in the tracker on November 1 of the succeeding CIP year, beginning in 1994. The RUD-OAG also recommended an initial compliance filing within 60 days of this Order which would list all projects the Company believes qualify for the incentive and the associated energy savings goals.

The Department recommended that the program be limited to a two year pilot project, as the Commission has done for all other DSM incentive programs.

The ALJ recommended approving Minnegasco's DSM incentive proposal to recover 100 percent of its lost margins from direct impact programs. He agreed with the RUD-OAG that CIP participants should be excluded from the comparison group for measuring lost margins. The ALJ agreed with the Department and OAG that lost margins should be booked annually, rather than monthly. He found that annual compliance filings were appropriate.

3. Commission Analysis

[Minn. Stat. § 216B.16, subd. 6c \(1992\)](#) sets out the following factors the Commission is to consider when evaluating financial incentives:

- (1) whether the plan is likely to increase utility investment in cost-effective energy conservation;
- (2) whether the plan is compatible with the interest of utility ratepayers and other interested parties;
- (3) whether the plan links the incentive to the utility's performance in achieving cost-effective conservation; and
- (4) whether the plan is in conflict with other provisions of the statute.

The Commission put forth the following principles for developing proposed incentive plans in its October 18, 1991 Order requiring gas utilities to file DSM incentive proposals:

Utilities should tailor their incentive plans to meet their own individual needs . . .

. . . The Commission . . . expects financial incentives to be tied to cost effectiveness.

... financial incentives should be tied to achieving objective demand side goals. Awarding financial incentives for spending money without results would serve no useful purpose and would undermine the legislative goal of achieving significant reductions in Minnesota energy use.

***19** The Commission has approved several different types of DSM incentive mechanisms for Minnesota utilities, including 100 percent lost margin recovery, 100 percent lost margin recovery with a bonus, and incentives which vary the amount of lost margin recovery based on performance. There are a variety of potential DSM incentive mechanisms which can achieve the goals set out in statute and the principles outlined by the Commission.

The Commission notes that Minnegasco has a large CIP program with a relatively wide variety of projects. The Company has considerable experience in successfully running these programs, starting with its participation as one of the utilities in the pilot utility conservation improvement program (PUCIP) which started in 1980. The Commission finds that it would be valuable to look at the effect of a positive financial incentive mechanism, rather than simply removing the obstacle of lost margins, for a utility such as Minnegasco. The Commission finds that either the Department or the RUD-OAG proposal would provide a positive financial incentive to Minnegasco, since the Company has the opportunity to recover more than 100 percent of its lost margins.

The Commission will adopt the RUD-OAG proposal. This financial incentive mechanism employs a continuous sliding scale recovery, thereby providing an increased incentive for achieving energy savings at every step. The Commission finds that the RUD-OAG proposal provides an appropriate level of bonuses and penalties; the Company must achieve at least 50 percent of its energy savings goals before it is eligible for a bonus, and has the potential to receive up to a 20 percent bonus for exceeding its goals. The threshold for achieving recovery and the potential bonus are both higher than under the Department proposal.

The Commission rejects Minnegasco's argument that it is unreasonable to require that a performance threshold be met before lost margin recovery is allowed. In prior orders for other companies, the Commission has found that it is just as reasonable to penalize substandard conservation performance as it is to reward satisfactory or outstanding performance.¹⁰

Minnegasco proposed to measure lost margins by comparing the consumption levels of CIP participants with the consumption levels of a comparison group of similarly situated ratepayers. The Commission agrees with the RUD-OAG that this is generally a workable approach, but that it should be refined to exclude CIP participants from the comparison group, for greater accuracy.

The Commission will require the Company to file a calculation of lost margins for a given CIP year by November 1 of the succeeding year, beginning with November 1994, as recommended by the parties. The Commission will also adopt the RUD-OAG recommendation to require an initial compliance filing that lists all projects the Company believes qualify for the incentive and the associated energy savings goals. This will help ensure that all parties understand and agree on the specific parameters of the program before proceeding.

***20** The Commission has structured all current DSM financial incentive programs as two-year pilot projects. The Commission will do so for Minnegasco also. This structure allows the Commission to review the program in a timely manner and determine if incentive plans are working as intended, need modification, or whether the entire issue should be revisited.

XIV. OVERALL FINANCIAL SUMMARIES

A. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate rate base for the test year is \$275,055,140 as shown below:

UTILITY PLANT IN SERVICE	\$524,943,057
Accumulated Depreciation and Amortization	(236,253,545)
	288,689,512
Gas stored underground:	
Current	18,214,000
Non-current	997,000
Accumulated Deferred Income Taxes	(28,733,000)
Materials and Supplies	3,049,000
Cash Working Capital	(6,493,737)
Deferred Debits and Credits	(4,235,635)
Other Working Capital	3,568,000
TOTAL RATE BASE	\$275,055,140

B. Operating Income Statement Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional operating income for the test year under present rates is \$21,206,518 as shown below:

OPERATING REVENUES:

Gas Sales	\$448,887,256
Other Revenues	2,219,000
Total Operating Revenues	451,106,256

OPERATING EXPENSES:

Cost of Gas	305,567,255
Production and Maintenance	13,412,723
Distribution and Utilization	14,257,783
Depreciation and Amortization	23,341,397
Customer Service and Information	5,160,029
Sales and Customer Accounts	16,025,114
Administrative and General	21,782,555
Other Expense	895,000

Taxes Other Than Income	22,234,000
Federal and State Income Taxes	6,650,588
Total Operating Expenses	429,326,444
TOTAL OPERATING INCOME	\$21,779,812

C. Gross Revenue Deficiency

*21 Based on the Commission findings and conclusions, the Minnesota jurisdictional revenue deficiency for the test year is as shown below:

Rate Base	\$275,055,140
Rate of Return	10.41%
Required Operating Income	\$28,633,240
Operating Income	21,779,812
Income Deficiency	\$6,853,428
Revenue Conversion Factor	1.67977
Revenue Deficiency	\$11,512,000

XV. REMAINING CONTESTED RATE DESIGN ISSUES

A. Revenue Apportionment to the Customer Classes

MEC, a party to these proceedings but a non-signatory of the Settlement, challenged the revenue allocation among the customer classes proposed in the Settlement. In its consideration of the Settlement, the Commission considered MEC's claim that the revenue allocation was unreasonable. The Commission rejected MEC's claim and found that the Settlement's revenue allocation was reasonable, pursuant to the following analysis.

In the Amended Offer of Partial Settlement, the parties proposed the following rate increases and decreases:

Residential	+7.30 percent
Commercial & Industrial Sales	+2.63 percent
Large-Volume Commercial and Industrial	+0.00 percent
Small-Volume Dual Fuel	+7.90 percent
Large-Volume Dual Fuel	+0.00 percent

MEC was not content that rates for Large-Volume customers remain unchanged while rates for all the other classes increased. MEC proposed that the rates for Large-Volume customers actually decrease. Under MEC's proposal, rates for the Residential

and small Commercial and Industrial customers would increase and rates for all of the other customer classes would decrease. MEC proposed rate increases and decreases which it modified in surrebuttal testimony to the following:

Residential	+8.9 percent
Small Commercial & Industrial Sales	+8.9 percent
Commercial & Industrial Sales	-5.4 percent
Large-Volume Commercial and Industrial	-3.52 percent
Small-Volume Dual Fuel	-3.28 percent
Large-Volume Dual Fuel	-6.76 percent

***22** MEC argued that the Settlement's revenue allocation would perpetuate what it characterized as the subsidization of residential and small C&I customers by the Large Volume C&I and Dual Fuel customers. MEC also argued that an 8.9 percent rate increase for Residential customers would not be large enough to cause "rate shock" and would move the Company more rapidly toward cost-based rates.

MEC failed to persuade the Commission that the Settlement's revenue allocations were outside the range of acceptable regulatory practice so that the resulting rates are unfair and unreasonable. Judgements as to what constitutes rate shock and how far and how rapidly the Commission should move toward cost-based rates are uniquely legislative decisions left to the Commission's sound discretion. In addition to cost, there are other critical rate design considerations. As the Minnesota Supreme Court has stated:

Once revenue requirements have been determined, it remains to decide how, and from whom, the additional revenue is to be obtained. It is at this point that many countervailing considerations come into play. The Commission must balance factors such as cost of service, ability to pay, tax consequences, and ability to pass on increases in order to achieve a fair and reasonable allocation of the increase among the customer classes. *St. Paul Area Chamber of Commerce vs. Minnesota Public Service Commission*, 251 N.W. 2d 350 (1977).

The Commission has recognized that moving prices toward cost is a reasonable policy. The Commission generally supports the movement toward cost-based pricing, but recognizes that there are other non-cost factors that are equally important. For example, the Commission has stated:

Avoiding rate shock is a primary ratemaking goal, because sudden, drastic increases in energy costs can be burdensome for residential and non-residential ratepayers alike. Avoiding rate shock is particularly important for residential ratepayers, however, because increases in the cost of basic needs can cause hardship for customers on low or fixed incomes. *In the Matter of the Application of Midwest Gas, a Division of Iowa Public Service Company, for Authority to Change Its Schedule of Gas Rates for Retail Customers within the State of Minnesota*, Docket No. G-010/GR-90-678, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (July 12, 1991), p. 35.

Furthermore, the Commission recognizes that cost studies and their underlying economic theories necessarily involve some imprecision. This imprecision adds to the Commission's unwillingness to place the entire rate increase on residential customers and small businesses, as MEC proposed. Given these considerations, the Commission finds that the revenue allocations proposed in the Settlement are reasonable.

B. Residential Customer Charge

1. Historical and Factual Background

***23** The residential customer charge is the fixed monthly rate residential customers pay for being hooked up to Minnegasco's system. Minnegasco proposed raising the customer charge for residential customers to \$5.00 from \$3.00 per month. The Department proposed an increase to \$5.50 and the RUD-OAG proposed leaving the customer charge at \$3.00. The parties reached no agreement on this issue and it was litigated in the contested case proceeding. (Customer charges for the other customer classes were agreed to by the parties to the Settlement.)

In setting the level of a customer charge, parties generally analyze the fixed cost of providing service to the customer class. Normally the monthly cost is determined through a Class Cost of Service Study (CCOSS) and is apportioned between the fixed monthly customer charge and the variable commodity charge. The proportional levels of these two factors have important effects on such issues as energy consumption, rate and revenue stability, and equity in and among customer classes.

In this rate case, the parties to the Settlement adopted the Department's Class Cost of Service Study (CCOSS) for the purpose of setting rates. This study demonstrated fixed residential customer costs of \$14.62 per month. Minnegasco did not believe there was a significant enough difference between the numbers in its CCOSS and the Department's to contest the Department's study. Both parties agreed that rate shock would occur if rates for the residential class were exactly aligned with the cost of service.

2. Positions of the Parties; Recommendation of the ALJ

Minnegasco — The Company proposed to increase the residential customer charge from \$3.00 to \$5.00. The Company argued that a \$2.00 increase was a reasonable move towards the \$14.62 stipulated class cost of service in this case. The Company argued that a \$5.00 customer charge would only recover approximately 35 percent of its embedded customer costs.

Minnegasco argued that a higher customer charge would give it greater financial stability because the fixed monthly charge would provide it with additional revenue independent of weather conditions and customer gas usage.

Minnegasco also argued that moderating the increase to \$5.00 instead of going right to full cost, i.e. \$14.62, would make the increase more acceptable to customers and maintain a reasonable degree of continuity with the Company's historical rates.

The Department — The Department proposed to increase the customer charge to \$5.50. The Department proposed a higher increase than the Company because it believes the Company's proposal does not move far enough in the direction of cost based rates. The Department also argued that a higher customer charge would promote economically efficient use of gas because rates would better represent cost and would allow ratepayer to make better informed decisions about the cost of the energy they consume.

***24** The Department agreed that revenue stability would be improved and Minnegasco would have a better chance of recovering its revenue requirement.

The Department argued that setting the customer charge closer to cost would reduce the potential for intra-class cross-subsidization of fixed costs between high use and low use customers.

RUD-OAG — RUD-OAG proposed leaving the customer charge at \$3.00 and allowing the Company to collect the entire class revenue deficiency through an increase to the energy charge. RUD-OAG argued that putting the entire increase into the energy charge would encourage energy conservation because energy consumption is sensitive to price.

The RUD-OAG relied heavily upon [Minn. Stat. § 216B.03 \(1992\)](#) to support its argument. Among other things, that statute states: "To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation . . ." The RUD-

OAG argued that increasing the proportion of fixed costs in the customer charge (and thereby decreasing the proportion in variable charges, which are tied to energy consumption) would diminish consumer incentives to conserve energy.

According to the RUD-OAG, analysis of a rate design proposal demands a balancing between the need for revenue stability and conservation goals. The RUD-OAG also argued that if a reliance on variable charges caused under-recovery in years with above-normal temperatures, this would eventually be balanced by over-recovery in years of below-normal temperatures.

RUD-OAG argued that maintaining the existing customer charge would give the Company a reasonable opportunity to meet its revenue requirement with the only difference between it and the Company's proposal being that more of the revenue requirement would be collected through the energy charge.

RUD-OAG believes its proposal would allow for a greater amount of historical continuity with prior rates and would promote a greater degree of customer acceptance of those rates because it would allow customers more control over their bills due to more of the cost being recovered through a variable charge.

The ALJ's Recommendation — The ALJ recommended adopting the Company's proposal for a \$5.00 customer charge. The ALJ found it appropriate to move in the direction of cost based rates and believes that a \$2.00 increase would be an appropriate step in that direction.

The ALJ concluded that a \$5.00 customer charge would improve the Company's revenue stability because it would allow the Company to recover more of its fixed costs on a steady basis and would reduce the Company's risk of under-recovering its revenue requirement in warmer than normal weather.

The ALJ recommended the Company's proposal over the Department's because he believes a \$5.00 rather than a \$5.50 customer charge would be more likely to gain customer acceptance and is more in line with historical rates.

3. Commission Analysis

***25** A rate design decision requires exercise of the Commission's legislative function. The Commission must weigh the facts in evidence to determine if the rate design proposed by the utility is justified and will result in just and reasonable rates.

The Commission agrees with the ALJ that Minnegasco's proposed increase to the residential customer charge should be approved. This position is reasonable and equitable, is not inconsistent with the facts in evidence, and is in line with prior Commission decisions.

In the 1992 Interstate rate case¹¹ the Commission adopted the Company's proposal for an increase to the residential customer charge, against opposition from the RUD-OAG. In that Order the Commission stated:

The Commission notes that customer charges are substantially below cost for all classes of customers. . . . As a result, the Commission believes an active step should be taken in this case to move these charges closer to cost. Moving prices toward cost is a reasonable policy which sends the proper price signals, spreads costs in an equitable fashion, and tends to eliminate intraclass cost subsidization.

Order at p. 44.

The Commission notes that in this case the present monthly residential customer charge is \$3.00 and fixed cost is approximately \$14.62. A move toward cost is warranted in this case and will promote the goals cited in the Interstate Order.

The Commission is aware of its statutory mandate to set rates to encourage energy conservation “[t]o the maximum reasonable extent.” Minn. Stat. § 216B.03 (1992). Even at \$5.00, the customer charge will not adversely affect the Commission's conservation goals because a substantial part of the Company's fixed costs will remain in the variable charge. This will provide customers with an incentive to conserve energy. Moreover, acting in its legislative mode, the Commission views any rate design proposal in its full context to determine what is reasonable in the context of the case. The Commission must balance such factors as fairness to ratepayer, conservation goals, revenue and rate stability when making a rate design decision. The Commission is also aware that the statute instructs the Commission to resolve all questions regarding reasonableness in favor of the consumer. Minn. Stat. § 216B.03 (1992). Having weighed the factors in this case, the Commission finds that Minnegasco's proposed increase in the residential customer charge will result in just and reasonable rates. The Commission will approve Minnegasco's increase.

C. Energy Charge for the Firm Customer Classes

*26 At issue was how the “energy charge” for Residential and C&I firm customer classes would be designed.

1. Historical and Factual Background

In this rate case, the term energy charge is used to describe the combination of the unit margin (also called the commodity-margin or the non-gas unit margin) and the per unit demand costs that are included in the base cost of gas and the monthly purchased gas adjustments (PGAs). This explanation is necessary because it is more common to use the term energy charge to refer to the entire variable cost of energy including the commodity cost of gas.

In its current rates, Minnegasco recovers its unit margin and its demand costs at a constant rate per unit of gas over the entire 12 months of the year. The only seasonal variability in Minnegasco's rates are due to seasonal difference in the commodity cost of gas and the amount of gas its customers buy during one part of the year versus another.

2. Proposals of the Parties; Recommendation of the ALJ

Minnegasco — Minnegasco proposed what it termed a “balanced energy charge.” The Company proposed to recover its pipeline demand costs on a seasonal basis at the same time those costs are incurred, i.e. higher PGA demand charges in winter, during the five month heating season from November through March, when it uses more firm pipeline capacity, and lower PGA demand charges in the summer, during the seven month non-heating season, when it uses less pipeline capacity.

To balance the seasonal fluctuations that would be caused by recovering its pipeline demand costs on a seasonal basis, however, Minnegasco also proposed to vary the non-gas unit (commodity) margin on a seasonal basis *in the opposite direction* from PGA demand costs. During the five month winter heating season when demand costs are higher the unit margin would be reduced and in the summer when demand costs are lower the unit margin would be increased. This arrangement would offset the difference between heating season and non-heating season demand costs with a seasonal unit margin and keep the total per unit energy charge, excluding the commodity cost of gas, constant.

Minnegasco argued for a balanced energy charge because it would provide Minnegasco with a more stable revenue stream and a better opportunity to recover its fixed costs under abnormal weather conditions because it would reduce the Company's dependence on a high level of winter throughput. Minnegasco also argued that under its proposal the demand component of the balanced rate would be more closely based on cost.

The Department — The Department proposed rates fully responsive to the seasonal fluctuation of pipeline demand costs. The Department stated that the Company's rates should reflect pipeline capacity costs at the time those costs are incurred. The Department argued that fully seasonal rates would send more appropriate price signals to Minnegasco's customers when the

Company's system is at its peak. The Department argued that seasonal rates have the potential for improving Minnegasco's system load factor, lowering system-wide peak demand costs and would better promote energy conservation.

***27 RUD-OAG** — The RUD-OAG proposed making no design changes to the unit margin and in the way PGA demand costs are recovered. The RUD-OAG recommended maintaining level demand charges and margins throughout the entire year without any seasonal variation. The RUD-OAG argued that the Company had offered no cost justification for its balanced energy charge proposal except to maintain level year-round rates which already exist.

The RUD-OAG also objected to the Department's proposal on the grounds that it would put too much of a burden on customers during the winter and cause rate shock. The RUD-OAG argued that the benefits that would result from increased conservation due to higher winter bills must be carefully evaluated against the additional financial burden higher winter rates would place on customers during the heating season.

ALJ — The ALJ recommended adopting the Department's proposal for seasonal, time-of-use rates. The ALJ believes the Department's proposal would encourage customers to use and conserve natural gas efficiently, while attempting to keep overall cost recovery from the class constant.

The ALJ found that the Department's seasonal rate proposal sends the best price signals to firm customers by increasing the demand rate they pay during the winter season and lowering it in the summer when gas is cheaper. The ALJ also found that the Department's seasonal rates reflect actual cost by keeping the unit margin constant throughout the year. Any rate shock on customer bills during the winter is balanced by cheaper bills during the summer, and leads to the same amount of annual revenue.

The ALJ also found that the availability of the Company's budget plan mitigates any hardship that could result from higher winter bills. The ALJ believes that recording on budget plan customers' bills the actual rate charged such customers during the winter sends appropriate price signals.

The ALJ also found that the Company failed to demonstrate a benefit to ratepayers from its balanced recovery proposal beyond maintaining level rates throughout the year, a result which is achieved already under the current rate structure and the Company's budget plan.

3. Commission Analysis

The Commission finds Minnegasco's proposal for a balanced energy charge is unacceptable. It does not send accurate price signals, does not offer any benefit to ratepayers above and beyond what exists under current rates, and does not appear practical from a regulatory standpoint.

The Commission is intrigued by the Department's seasonal rate proposal. The Commission is interested in exploring the potential benefits to be achieved through the implementation of seasonal rates that send accurate price signals to consumers. These benefits may be in the form of increased energy conservation and/or lower rates because of improvements in the efficient utilization of Minnegasco's distribution system during periods of peak demand.

However, the Commission finds that the Department's proposal in this case leaves too many questions unanswered about how seasonal rates would transmit price signals to customers and whether those signals would have enough impact on customers to be worth the change in rate design. The Commission is also concerned about the regulatory feasibility of changing rates outside of a rate case or a miscellaneous tariff filing and believes this issue needs to be explored more carefully in any future request for implementation of a seasonal rate.

***28** After careful consideration of the three rate design proposals the Commission finds that it is appropriate to leave the design unchanged as recommended by the RUD-OAG. The Commission will not require Minnegasco to develop and propose

a seasonal rate at this time because the Company's existing rate design already sends a price signal during the heating season based on seasonal commodity prices and customer gas usage. However, the Commission would entertain a more fully developed proposal in the future.

D. Three-Part Rate for Large-Volume Commercial and Industrial (C&I) Customers

The Department recommended that the Company design and propose a three-part rate for its Large-Volume C&I customer class. The Department argued that a three-part rate instead of the current two-part rate would be a more efficient pricing scheme because it would separate fixed costs, demand costs, and commodity costs on the customer's bill and would send a clear price signal to customers about the cost of using natural gas.

The Department recommended allowing the Company one year from the date of the final order in this rate case to design and propose a three-part rate for these customers in a miscellaneous tariff filing. The Department believed a year was needed because implementation would require each of these customers to install expensive tele-metering equipment at their place of business.

Minnegasco did not rebut the Department's position on the need for a three-part rate for this customer class and the ALJ did not make a recommendation on this issue. (All rate design issues for the Large-Volume C&I customer class were settled except for this one and the design of the energy charge.)

The Commission finds the Department's recommendation may warrant further consideration but will not require Minnegasco to make a proposal in a separate miscellaneous tariff filing. Rather, the Commission finds it would be a more efficient use of parties' and the Commission's time for Minnegasco to develop a three-part rate for its Large-Volume C&I customers as an alternative for parties to consider in its next rate case.

E. Additional Rate Classes for Small-Volume Dual Fuel Customers

The Department recommended that the Company examine whether there is a need for additional customer classes and tariffs for smaller, more homogenous groups of Small-Volume Dual Fuel (interruptible) customers. All rate design issues for the Small-Volume Dual Fuel customer class except this one were settled. The Department made its recommendation in response to the Company's proposal to offer this customer class a two-tier declining block rate.

Minnegasco did not rebut the Department's recommendation. The ALJ recommended that the Company prepare a study of Dual-Fuel customers for submission prior to its next rate case, analyzing appropriate subclasses or customer groupings.

The Commission finds that a separate study of this issue is not necessary at this time and rejects the Department's recommendation without prejudice. The Commission notes that the Department recommended this study in response to the Company's original proposal to offer a declining block rate. Subsequently, the parties agreed to a single, flat-rate unit margin in the Settlement. The Commission finds that any party may make a specific proposal for additional interruptible customer classes when the Company files its next rate case.

F. Process Interruptible Sales Service Rider

***29** Under Minnegasco's original proposal, process gas users with no alternative fuel capability would be eligible for the Small-Volume Dual Fuel rate if they were willing to accept curtailment upon notice from the Company. Minnegasco identified three other conditions that would have to be met for a customer to qualify for this rate: a signed contract accepting the curtailment provisions of the service, designation of three individuals that can be notified in the event of a curtailment and installation of tele-metering equipment at the customer's expense.

The Department agreed that an interruptible rate would be appropriate for these customers under these conditions. However, the Department did not agree that eligibility for the rate should be limited only to process gas users. The Department recommended making the rate available to all customers with these load characteristics. Minnegasco amended its proposal to incorporate the Department's recommendation.

The ALJ recommended approving Minnegasco's amended proposal. The ALJ found that the Process Interruptible Sales Service Rider would improve the Company's overall load factor to the benefit of all customers.

The Commission agrees with the Department and believes rates should be based on load characteristics and conditions of service rather than on what the gas is going to be used for. Therefore, the Commission accepts and adopts the ALJ's recommendation and approves the Company's amended Process Interruptible Sales Service Rider.

G. Main and Service Line Extensions

Minnegasco proposed an increase to the footage allowances for main and service line extensions provided to new customers without charge and decreases in the per foot charges for extensions in excess of the footage allowances. The Department agreed that the proposed changes were appropriate and would reflect Minnegasco's average cost for new extensions.

The Department also recommended that the Company add an economic feasibility formula to its tariff to clarify what criteria it uses to evaluate whether it needs to collect an extension charge, a contribution-in-aid-of-construction or a customer-advance-for-construction. The Department also suggested modifications that would require the Company to collect an advance-for-construction and make refunds under certain conditions instead of allowing the Company complete discretion over these decisions.

Minnegasco agreed to the Department's recommendations and proposed to incorporate them into its tariff when it makes its compliance filing. The ALJ found this tariff proposal to have merit.

The Commission accepts and adopts the ALJ's recommendation and approves the new extension footage allowances and excess footage charges. The Commission will require the Company to submit an economic feasibility formula and revised tariff language in its Compliance Filing as recommended by the Department.

H. Late Payment Policy for Commercial and Industrial (C&I) Customers

***30** Minnegasco proposed to extend the due date for C&I customers to pay their gas bills by 10 days, an increase from 15 to 25 days. This increase would give C&I customers the same amount of time as Residential customers to pay their bill before a late charge is assessed. The Department agreed that this would be a fair policy for all customers.

The ALJ did not make a specific recommendation on the late payment policy for C&I customers.

The Commission finds that the Company's proposal is reasonable and approves the extension of the late payment time period for C&I customers.

I. Therm Billing

Minnegasco proposed to bill all of its customers in therms because it would ensure that all of its customers receive an equivalent amount of energy for every unit billed. (A therm is a standardized unit of energy commonly used in the gas industry and is equivalent to 100,000 Btus.) Minnegasco proposed to replace its current Btu pressure adjustment with a therm factor adjustment.

The Department agreed this would be an appropriate change because it would ensure that all customers are billed using equivalent units of energy and that it would not have any impact on revenue. The ALJ recommended allowing Minnegasco to adopt therm billing.

The Commission accepts and adopts the ALJ's recommendation and approves the Company's proposal to bill all of its customers in therms instead of Btu-adjusted Ccfs.

J. Miscellaneous Tariff Book Organizational Changes

Minnegasco proposed several language and organizational changes to its tariff book that make the tariffs easier to use. None of the parties objected to these changes and the ALJ found they were reasonable and appropriate. The ALJ recommended that they be approved.

The Commission accepts and adopts the ALJ's recommendation and approves the Company's miscellaneous tariff book changes.

K. Continuity of Service

Minnegasco proposed to replace its tariff entitled Maintenance and Responsibility with a substitute tariff entitled Continuity of Service. Minnegasco's proposal would limit its risk for service interruptions and shifts some of that risk onto its customers. Minnegasco argued that NSP has been permitted to use language in its tariff that is practically identical to what Minnegasco has proposed.¹²

The Department argued against changing any of the existing tariff language because it believes the proposed language would unreasonably limit the Company's liability. The Department argued that the existing tariff language adequately addresses the Company's responsibility for providing an adequate and continuous supply of gas to its customers.

***31** The ALJ found that the Company's proposed language provides sufficient protection for customers and puts a reasonable limit on the Company's liability. The ALJ recommended adopting the Company's proposal.

The Commission is not completely persuaded by any of the arguments in favor or against maintaining the current standard of negligence and liability found in the Company's tariff and believes that further development and examination of the issues involved will be required. However, the Commission finds merit in the Company's proposal to limit its liability against claims resulting from loss of profits and other consequential damages due to service related problems because these kinds of losses are typically covered by a C&I or Dual-Fuel customer's own insurance.

Therefore, the Commission will maintain the current tariff language but permit the Company to add the following sentence:

Minnegasco will not be liable for any loss of profits or other consequential damages resulting from the use of service or any interruption or disturbance of service.

L. Right to Remove a Gas Meter

Minnegasco proposed to be allowed to remove the gas meter from a customer's premise if the customer has not used any gas for at least 12 months. Minnegasco argued that the customer charge alone does not cover the cost of keeping an idle meter in place.

The Department suggested modifying the Company's proposal to require Minnegasco to give its customers advance notice of its intention to remove a meter at a customer's premise and a requirement that the meters selected for removal are chosen on a non-discriminatory basis.

The ALJ recommended acceptance of the Company's proposal with the modifications suggested by the Department. The ALJ found that with the Department's modifications the proposal was reasonable.

The Commission agrees with the ALJ and will approve the Company's amended tariff entitled Minnegasco's Right to Remove a Gas Meter.

M. Customer Deposits

The Department proposed making it mandatory for Minnegasco to collect a deposit from all new and existing customers. The Department was concerned that allowing Minnegasco discretion over whether it collects a deposit from customers would make it too easy for Minnegasco to administer its customer deposit program in an unfair or discriminatory manner.

The Company objected because it currently does not collect a deposit from any of its customers. The Company argued that a deposit program would cost more to administer than it would save by reducing unpaid bills. The Company also argued that a mandatory deposit program would be inconsistent with the Commission's Rules which allow a utility to collect a deposit only if the customer has an unsatisfactory credit or service record as determined using the criteria set forth in [Minn. Rules parts 7820.4100-.4700](#).

The ALJ recommended accepting the Company's tariff language as originally proposed because it is consistent with the Commission's rules on customer deposits and adequately describes the Company's customer deposit policy.

***32** The Commission agrees with the ALJ's recommendation and approves the Company's tariff as originally proposed. In light of Minnegasco's current practice of charging no deposit to any customer, the expense to Minnegasco and detriment to all customers of requiring the Company to collect a deposit from all customers clearly outweighs the value of guarding against potential discriminatory application of some future deposit requirement.

N. No Charge Service

The Department recommended changing the name of the Company's No Charge Service tariff to No Surcharge Service. This tariff describes some of the services Minnegasco provides to customers without any additional charge including emergency leak inspections, maintenance of meters, pressure regulator and service lines and meter turn-ons for new customers. The Company did not object to the Department's proposal and the ALJ recommended adopting it.

The Commission finds the Department's recommendation is reasonable and approves the new title for this tariff.

O. New Area Surcharge

Minnegasco proposed a New Area Surcharge Rider that would allow it to extend service to areas where service cannot be economically justified under Minnegasco's present rates. The New Area Surcharge Rider would allow Minnegasco to add a fixed monthly surcharge to customer bills for no longer than 10 years or whenever Minnegasco recovers its incremental cost of providing service to the new area, whichever comes first.

The Department agreed that a New Area Surcharge would be appropriate but objected to Minnegasco's proposal because it did not contain enough details for the Department to make an evaluation and did not conform to the New Town Rate that was approved for Northern Minnesota Utilities in Docket No. G-007/M-92-212.¹³ The Department recommended rejecting the New Area Surcharge Rider and requiring the Company to make a separate miscellaneous tariff filing. The Department argued that this would ensure the Rider received an adequate level of review.

The Company agreed to redesign its tariff in conformance with Northern Minnesota Utilities' New Town Rate but proposed to do this as part of its compliance filing in this rate case.

The ALJ recommended approving a New Area Surcharge Rider for Minnegasco as consistent with the Commission's decision regarding Northern Minnesota Utilities' New Town Rate. The ALJ recommended allowing Minnegasco to make its revised filing a part of its rate case compliance filing and suggested allowing parties additional time to comment on this particular issue. In response to questions during Oral Arguments the Department stated that it would not object to reviewing the Rider as part of the rate case compliance filing.

***33** The Commission believes that a New Area Surcharge Rider is appropriate but that it will need to review the Company's modified language of that rate before granting final approval. The Commission finds that review of the modified rate language in a compliance filing will afford adequate opportunity to address the issue. Therefore, the Commission will approve Minnegasco's modified New Area Surcharge Rider provisionally, i.e. subject to review in the Company's compliance filing.

P. Reconnection Charges

Minnegasco proposed an increase for all customer reconnection charges to \$35 from the current level of \$10 for customers who have had their meter locked for non-payment of their bill and \$20 for customers who have had their meter removed for non-payment of their bill. Minnegasco argued that it costs the same to reconnect a customer regardless of the reason service is terminated and that charging a below cost reconnection charge to some of its customers sends an inaccurate price signal about the cost of not paying the gas bill.

The Department objected to Minnegasco's proposal and suggested that the reconnection charge for non-payment of a bill should be \$15 and the reconnection charge for all other reasons such as meter tampering should be \$35. The Department argued that it is more important to maintain access to service for low income ratepayer who have trouble paying their bills than it is to send the correct price signal about reconnection charges. The Department argued that it was important to try and maintain these people on the system and that a too high reconnection charge would prevent them from getting back onto the system after a disconnection. The Department did not object to the \$35 reconnection charge for meter tampering, breach of contract and fraudulent use of services.

The ALJ recommended adopting the Department's proposal for a \$15 and a \$35 reconnection charge depending on the Company's reason for disconnecting the customer's service. The ALJ believes that customers should not be penalized for reasons due to economic hardship to the same extent as customers who wrongfully avail themselves of the Company's property and services.

The Commission agrees with the Department's and the ALJ's recommendation for a \$15 reconnection charge for non-payment of a bill. The Commission finds that a higher charge may contribute to another cycle of non-payment of bills.

The Commission also finds that a \$50 reconnection charge for reasons other than non-payment of a bill would be more appropriate than a \$35 charge. The Commission believes that a higher reconnection charge for customer malfeasance will help offset some of the cost of allowing a lower reconnection charge for customers who are disconnected for non-payment of their bill. The Commission finds this two-fee rate structure is consistent with its decision in the 1991 NSP-Electric rate case.¹⁴ In that case, the Commission viewed the relock issue with the utmost seriousness and found that customer tampering with Company equipment is a violation of the law as well as a safety hazard and an infringement on the Company's right to disconnect service for non-payment.

Q. Seasonal Sales Cooling Service Rider

***34** The Company proposed a Seasonal Sales Cooling Service Rider for separately metered, gas powered, energy efficient, air conditioning equipment that would make interruptible rates available to these customers off-peak between April 15 and October 15. The Company argued that this would encourage investment in gas powered air conditioning equipment, help the Company improve its off-peak system load factor and reduce the amount of electricity needed for summertime air conditioning.

The Department objected to the Company's proposal to offer a reduced rate to customers based on the customers' end-use for the gas. The Department argued that rates should be based instead on cost of service and load characteristics and that only if the customer meets the established criteria for a reduced rate should the customer be entitled to the reduced rate. The Department also argued that if the Company wanted to request permission to recover funds invested in natural gas air conditioning equipment because of potential conservation benefits, then the appropriate place to make that request would be in a CIP plan budget proposal.

The ALJ agreed with the Company and found that the use of gas for summertime air conditioning is likely to improve the Company's overall load curve to the advantage of all of its customers. The ALJ also found that it would be in the public interest to allow this rider because it would help reduce demand for electricity when electric utilities are at their summertime peaks. The ALJ did not agree with the Department's argument that the appropriate place to make this kind of proposal was in the Company's CIP plan.

The Commission agrees with the Department and will not allow the Company to charge natural gas air conditioning customers a reduced rate because of their end use for the gas. The Commission finds that rates should be based on a customer's load characteristics and that to qualify for an interruptible rate a customer will have to meet the criteria established in the Company's tariffs for those rates.

R. Water Pumping Sales Service Rider

Minnegasco proposed to reduce the Commercial and Industrial energy charge for municipal water pumping customers. The Company argued that a lower rate for these customers would promote the use of natural gas powered water pumping equipment and improve the Company's overall load curve.

The Department objected to the Company's proposal because it would make a reduced rate available to a customer on the basis of the customer's end-use for the gas. The Department argued that rates should be based on load characteristics and cost of service. The Department argued that municipal water pumping customers should receive whatever rate they are entitled to on the basis of how much gas they use and whether they are willing to be interrupted rather than on the basis of a seasonal difference in gas usage.

The ALJ recommended approving the rider because of its potential for improving the Company's overall load curve and for decreasing the demand for electricity in the summer. The ALJ believes these potential benefits outweigh any harmful impact rate discrimination might have on the Company's other Commercial and Industrial customers.

***35** The Commission agrees with the Department and will not approve a reduced Commercial and Industrial rate for municipal water pumping customers because of their end use for the gas. The Commission finds that rates should be based on a customer's load characteristics and that to qualify for a reduced rate a customer will have to meet the criteria established in the Company's tariffs for the reduced rate.

S. Natural Gas Vehicle Service Rider

Minnegasco proposed a Natural Gas Vehicle Service Rider that would allow it to give a \$2.00 per Mcf credit to Commercial and Industrial Sales Service customers who use natural gas as fuel for dedicated natural gas vehicles (NGVs). Under Minnegasco's proposal for a customer to qualify for this rate all NGVs would have to run exclusively on compressed natural gas, the customer would have to own and run its own gas compressor and the gas would have to be separately metered. In addition, the rate would only be available for a term of four years and would be used to help defray the cost of investing in dedicated NGVs.

Minnegasco argued that the use of alternate fuels in NGVs would reduce the level of air pollution and reduce the United States dependence on foreign oil. Minnegasco argued that these are compelling public policy reasons for approving this rider.

The Department objected to the Company's proposal because it would be a discriminatory rate based on end use rather than load characteristics or cost of service. The Department argued that Minnegasco's ratepayer should not be expected to subsidize private investment in NGVs. The Department also argued that if there are compelling public policy reasons that warrant subsidizing investment in NGVs then the Company's shareholders or taxpayers should pay for those subsidies.

The Department also argued that gas for use in dedicated NGVs is a year-round load and would add capacity costs during the winter as well as the summer. The Department argued that if these customers are buying gas under the same conditions as other firm customers they should pay the same rates as other firm customers. But if they are willing to risk being interrupted then they should be entitled to an interruptible rate.

The ALJ recommended approving the rider because an increase in the use of alternate fuels in NGVs would help promote the public policy objective of cleaner air and reduced dependence on foreign oil.

The Commission agrees with the Department and will not approve a \$2.00 per Mcf credit to the applicable Commercial and Industrial Sales Service rate for gas purchased for use in NGVs. The Commission finds that the Company's proposal would create a discriminatory rate based on end use instead of a rate based on load characteristics and cost of service. The Commission finds that to the extent that the Company's proposal would help society attain cleaner air and reduce the United States dependence on foreign oil it would be more appropriate for Minnegasco (or the NGV owners) to seek recovery of the \$2.00 per Mcf investment from all of the beneficiaries of the those policies rather than just Minnegasco ratepayers.

ORDER

***36** 1. Minnegasco is entitled to increase gross annual Minnesota jurisdictional revenues by \$11,512,000 in order to produce total gross annual jurisdictional operating revenues of \$462,618,256.

2. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement and the rate design decisions contained herein, along with the proposed effective date.

3. The compliance filing filed pursuant to Ordering Paragraph 2 shall contain:

a. Schedules showing all billing determinants collecting the total annual gross operating revenues from the sale of gas in the amount of \$460,399,256. These schedules shall include but not be limited to:

1. Total revenue by customer class,
2. Total number of customers, the customer charge and total customer charge revenue by customer class,
3. Total number of commodity related billing units, the per unit commodity and demand cost of gas, the non-gas unit margin and total commodity related sales revenue by customer class.

b. A revised version of the Company's Gas Rate Book incorporating the rate design decisions contained in this Order and including but not limited to the following:

1. The \$5.00 per month Residential Class customer charge and the customer charges contained in the stipulation,
2. The stipulated class revenue apportionments,
3. The Process Interruptible Sales Service Rider as agreed to by the parties,
4. The main and service line footage allowances extension charges as agreed to by the parties,
5. The extension of the late payment period for the C&I customer class by 10 days to correspond to the Residential customer class late payment period,
6. Therm billing,
7. The tariff changes not specifically referred to in this order except in Section XIII, J that are of a housekeeping nature,
8. The addition of the last sentence in Minnegasco's proposed language on continuity of service to the existing tariff on Maintenance and Responsibility,
9. The tariff language on Minnegasco's Right to Remove a Gas Meter as agreed to by the parties,
10. Minnegasco's customer deposit tariff language,
11. The renaming of the No Charge Service tariff to No Surcharge Service,
12. The increased reconnection charges of \$15.00 and \$50.00 depending on the reason for disconnection.

c. Proposed customer notices explaining the final rates.

d. A proposal for a separate customer notice on therm billing to be distributed in customer bills when therm billing goes into effect.

4. Within 30 days of the date of this Order, the Company shall file with the Commission and serve on the parties, a revised base cost of gas and supporting schedules incorporating the changes made herein. The Company shall also file its automatic adjustment establishing the proper adjustment to be in effect at the time final rates become effective. The Department shall review these filings as it does other automatic adjustment filings.

***37** 5. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve upon all parties to this proceeding, a proposal to make refunds, including interest calculated at the average prime rate, or other appropriate adjustments, to affected customers. The proposal shall reflect the difference between the revenue collected during the interim rate period and the amount authorized herein.

6. Within 30 days of the service date of this Order, the Company shall file proposed extension tariff language that includes an economic feasibility formula detailing the conditions under which Minnegasco can waive extension charges and requiring the Company to collect advances-for-construction and make refunds under certain conditions.

7. Within 30 days of the date of this Order, the Company shall file with the Commission for its review and approval, and serve on all parties in this proceeding, a modified New Area Surcharge Rider as discussed herein.

8. Parties shall have 15 days to comment on the filings required in Ordering Paragraphs 1 through 7.

9. Within 60 days from the date of this Order, the Company shall file an update of its MGP cleanup cost recovery activities to date, including what claims it has filed, and what efforts it has made to identify and recover costs from other potential parties. Minnegasco shall also file information showing what future actions it plans to take and a schedule of those activities with regard to recovery of its MGP costs from insurance companies and other parties.

10. Within 60 days from the date of this Order, the Company shall file a report that explains and defines the categories of expenses that Minnegasco proposes to classify and recover as MGP cleanup costs.

11. Within 60 days of the date of this Order, the Company shall file with the Commission and serve on the parties a filing detailing which programs are eligible for lost margin recovery and the associated energy savings goals. Parties shall have 30 days to comment on this filing.

12. On an annual basis, beginning no later than November 1, 1994, instead of its current annual filing date, the Company shall file with the Commission and serve on the parties its annual conservation tracker account report. This report shall include conservation costs incurred, the conservation costs recovered, and the balance in the tracker account. This report shall also include the Company's calculations of actual lost margins and energy savings goals achieved due to its conservation efforts. Parties shall have 30 days to comment on these filings.

13. On an annual basis, beginning April 1, 1994 the Company shall file with the Department, an update of FAS 106 funding. This update shall include: 1) the existing funding situation; 2) tax-deductible alternatives available to Minnegasco; 3) a five year forecast of future funding levels; 4) the amount of equity in Arkla's and Minnegasco's capital structures; and 5) the existing post retirement benefit obligation.

***38** 14. Minnegasco shall file on an annual basis the amount of its expenditures for the year and its cumulative expenditures to date for MGP costs. The annual reporting of these costs shall explain and show the types of costs that were incurred and what monies were recovered from insurance companies and other parties. This information shall be filed by April 1st of each year.

15. Minnegasco, in its next rate case, shall file information and provide calculations showing the impact on proposed final and interim rates of using an industry average capital structure. Minnegasco shall also file information describing the effect of manufactured gas plant cleanup costs, incentive compensation, vacation accruals, and winter leak surveys on test year costs and rate base.

16. Minnegasco, in its next rate case, shall develop a proposal for a three-part rate for its Large-Volume Commercial & Industrial Sales Service customer class.

17. This Order shall become effective immediately.

DISSENTING OPINION

Commissioners Storm and Burton, dissenting.

I. Introduction

In a generally accepted model of utility regulation, utilities as regulated monopolies give up certain marketplace opportunities and choices which are allowed nonregulated entities. Their regulators in turn permit the regulated utilities to present evidence of their revenue requirements in rate cases. A properly presented rate case will allow a utility to recover its prudently incurred expenses, plus a reasonable return on its investment.

As will be shown in the body of this dissent, Minnegasco did not overstep the bounds of the regulatory model in its treatment of prudent post-retirement employee benefits. Neither did Minnegasco fail in its burden of proof when it presented those expenses for recovery in its rate case. In addition, Minnegasco consistently abided by specific Commission requirements in its accounting treatment of the expenses.

Despite these facts, the majority has chosen to disallow a significant portion of Minnegasco's prudently incurred SFAS 106 expenses. We respectfully dissent from that portion of the majority opinion.

II. Factual Background

In the past, Minnegasco recorded PBOP expenses on a cash basis. In doing so, Minnegasco acted in accordance with standard utility practice. The ALJ recognized the prudence of Minnegasco's past accounting practices in Findings No. 46 and 53 of the ALJ's report. The Commission also found that Minnegasco's past treatment of PBOPs on a PAYGO basis was prudent. Order at p. 12.

In 1990 FASB changed its accounting standards for PBOPs from the cash basis to the accrual basis. The Commission issued its official response to the change in its September, 1992 ORDER ADOPTING ACCOUNTING STANDARD AND ALLOWING DEFERRED ACCOUNTING in Docket No. U-999/CI-92-96 (the FASB docket). In that Order the Commission stated:

The Commission adopts SFAS 106 accrual accounting for Minnesota utility recordkeeping and ratemaking purposes, subject to Commission review for prudence and reasonableness of the [PBOP] programs, expenses, and all calculations in future rate cases.

***39** Order at p. 6.

The Commission also established a process for utility changeovers to the new accounting method. The Commission authorized a three year deferred accounting period for utilities, with the deferred balance of PBOP expenses subject to Commission general rate case review. In its November 2, 1992 ORDER DENYING PETITION FOR RECONSIDERATION, GRANTING IN PART AND DENYING IN PART PETITIONS FOR CLARIFICATION in the FASB docket, the Commission clarified that deferred balances which were not brought forward for rate case review within the allowed three year period would be denied recovery.

On July 2, 1992, Minnegasco filed a general rate case in which it sought, among other things, recovery of its PBOP expenses. Test year PBOP expenses consisted of three component parts:

1. The year's service cost, the present value of the future benefits earned by current employees during the year;
2. The interest cost, equal to the discount rate used to determine the present value multiplied by the accumulated present value, of the total of expected future PBOPs;
3. The amortization of the transition obligation, which is defined as the present value of the accumulated expected future PBOP liability on the day SFAS 106 is adopted.

The Commission found that the current service component of Minnegasco's PBOP expenses was "reasonable, prudent, and recoverable in rates." Order at p. 10. The ALJ also recommended complete recovery of the transition obligation, together with

interest. The majority, however, disallowed one half of the transition obligation component, and one half of the associated interest.

III. Analysis

Analysis of Minnegasco's treatment of PBOPs brings us to the firm conclusion that the majority erred when it disallowed one half of the transition obligation and associated interest. Minnegasco experienced normal and ordinary expenses when it incurred liability for employees' post-retirement benefits. This category of expense is considered a normal cost of service in utility accounting, and is consistently treated as such in rate cases before the Commission. Prior to FASB accounting changes, Minnegasco accounted for the expenses in a manner consistent with prevailing industry practice and approved by the Commission in the Company's rate cases. Minnegasco changed to accrual accounting for PBOPs for ratemaking purposes in response to the Commission's direction in the September 22, 1992 Order addressed to all utilities. After Minnegasco's accounting change took place, the Company proposed an ongoing PBOP accounting plan in this rate case; neither the prudence of the plan nor its calculations was contested. Since the new accounting plan, pursuant to Commission direction, was based on the accrual method, a transition obligation was an inevitable and integral part of the proposed rate case expenses.

After reviewing this history, we are convinced that there was no action by Minnegasco at any time which converted a normal, ordinary, prudently incurred business expense into something for which shareholders should be penalized by disallowance. (Indeed, it is unclear how Minnegasco could have prudently made any other decisions throughout this period.) The benefits paid to employees and the timing of the payments are exactly the same under the PAYGO and the accrual methods. The character and the amount of the obligation remain unchanged; only the manner of booking the expense for accounting purposes changes. Nothing increases ratepayer liability or renders a prudent cost imprudent. An accounting change should not distract the Commission from its basic examination of the prudence and reasonableness of costs of service for rate case recovery. The PBOP costs under the accounting change, including the transition obligation and associated interest, were reasonable and prudent and should be recovered in full.

***40** Because Minnegasco adhered to sound regulatory practice in its treatment of PBOP costs and in its presentation of the expenses for rate case recovery, the Company should recover these prudent costs of utility service. We believe that this fundamental principle is ignored or misunderstood in the majority opinion. No reasoning offered by the majority convinces us otherwise.

1. The Test Year Concept

The majority focuses strongly upon a philosophical discussion of the test year principle. We agree with the majority that the test year is a useful device for balancing revenue and expense to arrive at a revenue requirement. However, nothing in the basic concept of the test year requires disallowance of these PBOP expenses.

The majority states that the transition obligation is an out-of-test year expense and therefore cannot be recovered. (Although, inexplicably, the Company is later allowed to recover one half of the transition obligation). In actuality, the obligation was recognized in the test year.

The majority lists a host of regulatory evils against which the test year concept stands as a bulwark. We believe that even if the transition obligation were considered an out-of-test-year expense, none of the cited evils would be present in this case. As will be explained later, there is no inequitable intergenerational matching present. The costs for which recovery is sought are "representative, not aberrant." There is absolutely nothing in the record to indicate that the proposed expenses are based on "conjecture" instead of "facts and experience." On the contrary, the expenses were determined carefully and precisely, using calculations accepted by all the parties. There is no need for the test year to act as a "regulatory safeguard against under-recovery, overrecovery, [or] imprecision in ratemaking" in this case.

In short, the Commission should continue to view the test year as a tool in arriving at the revenue requirement component of just and reasonable rates. The test year concept should not overshadow considered Commission judgment on the prudence and reasonableness of incurred expenses.

2. The Matching Concept

The majority holds that one half of the transition obligation should be disallowed because it produces an improper match between the time a cost is incurred and the recovery of that cost. The truth is that neither PAYGO or SFAS 106 accrual accounting, or any other accounting method, produces a perfect match. The SFAS 106 method, however, is a move toward better matching.

Under the PAYGO method, liability is incurred when service is rendered in the present, but that liability or cost is not recognized until benefits are paid in the future. If the incurring of a future liability is recognized as a present cost, as under SFAS 106 accounting, PAYGO may be viewed as the ultimate mismatch.

Under the SFAS 106 accrual method, the present value of future liabilities is booked at the time those liabilities are incurred, when present service is rendered. SFAS 106 accounting achieves a better match of the incurring of the obligation with both recognition of the cost and recovery from ratepayers. Because the transition obligation is an integral part of the changeover from cash basis to accrual basis, it is part of the move to better matching. The transition obligation actually accelerates the matching process, allowing recovery to rest with present ratepayers, who are more likely than future ratepayers (who would pay under PAYGO) to have rendered the service from whence the transition obligation arose.

***41** The majority seems to believe that the transition obligation produces a mismatch which is akin to retroactive ratemaking. “It results in one group of ratepayers bearing expenses that would have been charged to another group, given perfect information earlier.” Order at p. 4. In its September 22, 1992 Order, the Commission specifically found that the transition obligation does not result in retroactive ratemaking:

While under pay-as-you-go accounting [PBOP] expenses are recognized at the same time as they are paid out to employees, the employee services from which the benefits arose occurred in the past. This imperfect matching of expense recognition with employee services also occurs if a transition obligation is recognized. Recovery of [PBOP] costs under pay-as-you-go accounting has never been considered retroactive ratemaking, and neither should the recovery of a transition obligation which arises as a result of a change to accrual accounting. Neither of these situations is the type of reaching back for past costs which the retroactive ratemaking doctrine prohibits. The utility is not in either case attempting to recover in current rates costs which should properly have been recovered in past rates.

Order at pp. 5-6.

3. The Benefits to Shareholders

The majority disallows one half of the transition obligation amount because the transition obligation “. . . benefits investors so significantly that apportioning part of the transition cost to them is reasonable.” Order at p. 4. We find this reasoning flawed.

The SFAS 106 benefits to shareholders mentioned by the parties are more accurate financial reporting and more precise identification of costs. There is nothing in the record to show that these benefits would not result in more prudent managerial decisions, benefiting ratepayers at least as much as shareholders. More accurate financial reporting and identification of costs impose no burden or higher cost on ratepayers; employee benefit payouts remain unchanged after the switch to accrual accounting. There is absolutely no reason to penalize shareholders by a 50% disallowance because an accounting change has brought about greater accuracy and accountability in company recordkeeping and financial reporting.

4. Extraordinary Expenses

The majority states that a disallowance of employee benefit expenses would be “. . . consistent with Commission action in other cases involving extraordinary expenses that do not fit within established rate case categories.” PBOP expenses, however, are not extraordinary expenses, but normal and ordinary costs of providing utility service. The only meaning of the term “extraordinary” which could possibly be applied to these expenses is a definition found in *Webster's Third New International Dictionary*: “not of the usual order or pattern.” The only thing “not of the usual” about these expenses is the one-time change in their recognition from cash basis to accrual. This accounting change does not render an ordinary, normal and necessary cost of providing service into something extraordinary, for which disallowance is justified.

5. Other Regulatory Bodies

***42** The majority cites actions taken by other regulatory bodies as justification for the disallowance of Minnegasco's expense. The majority notes a partial disallowance of coal tar clean up costs by the Illinois Commerce Commission and a partial disallowance of the costs of a management incentive plan by the Vermont Public Service Board.

These cited regulatory actions do not involve sets of facts similar to those before the Commission. Neither case addresses disallowances of otherwise inarguably ordinary and prudent expenses because of changes in booking the expenses. In cases in which regulators have addressed SFAS 106 accounting questions, the expenses, including the transition obligation, have been allowed. Wisconsin and California public utility commissions, as well as others, have adopted SFAS 106 accounting, including the recognition of the transition obligation for ratemaking purposes. The Federal Energy Regulatory Commission has endorsed the policy of allowing recovery of the transition obligation. While these decisions certainly do not bind our Commission, they are instructive.

IV. Conclusion

Within the framework of utility regulation, regulators have a responsibility to both ratepayers and utility shareholders. This is intrinsic to the dynamic “give and take” of the regulatory model.

Public utility commissions have the duty to ensure that ratepayers are provided high quality service at fair and reasonable rates. Ratepayers must be protected from discriminatory and unfair treatment by regulated monopolies. Goals of universal service must be promoted when possible.

Regulators also have a responsibility to utility shareholders. Shareholders have a right to expect that prudent and reasonable managerial decisions will allow them to achieve a reasonable return on their investment, comparable to returns made on investments and other business undertakings of corresponding risks and uncertainties. Shareholders have a right to regulatory decisions which will enable the utility to maintain its financial integrity and attract new capital on reasonable terms. See, *Bluefield Water Works and Improvement Co. v. P.S.C.*, 262 U.S. 679 (1923) and *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

For the reasons stated in this dissenting opinion, Minnegasco has the right to recover its prudent expenses for post-retirement employee benefits, including the transition obligation inherent in the Commission-sanctioned accounting method. Allowing Minnegasco full recovery of these prudent and reasonable costs of service would fulfill the Commission's responsibilities toward both ratepayers and shareholders.

AMENDED OFFER OF PARTIAL SETTLEMENT

The undersigned parties to this proceeding have entered into this Amended Offer of Partial Settlement (“Settlement”) which resolves many of the disputed issues between the parties in the above referenced Dockets. In so doing, no party is admitting or supporting any of the positions agreed upon on any specific issues, other than for purposes of this Settlement.

BACKGROUND

*43 On July 2, 1992, Minnegasco, a Division of Arkla, Inc. (“Minnegasco”) filed a petition seeking a general revenue increase of \$24,823,000 or 5.5 percent. On August 17, 1992, the Minnesota Public Utilities Commission (“Commission”) issued an Order Accepting Filing and Suspending Rates, and a Notice and Order for Hearing referring the case to the Office of Administrative Hearings for contested case proceedings. On August 31, 1992, the Commission issued an Order Setting Interim Rates authorizing Minnegasco to collect \$11,800,000 in interim rates.

The Administrative Law Judge (“ALJ”) who will hear this matter is Richard C. Luis. A prehearing conference was held on August 27, 1992. The ALJ issued a Prehearing Order on September 17, 1992. The ALJ granted the Petitions to Intervene of the Minnesota Department of Public Service (“Department” or “DPS”), the Minnesota Office of Attorney General (“OAG”), Minnesota Energy Consumers (“MEC”), Honeymead Products Company, (“Honeymead”) the Suburban Rate Authority (“SRA”), and Northern Natural Gas Company (“Northern”).

Pursuant to the ALJ's Prehearing Order, Minnegasco's additional direct testimony and exhibits, filed September 14, 1992, concerning the Weather Normalization Adjustment (WNA) and FAS 106 constituted a supplemental filing. No parties objected to the inclusion of the supplemental information in the record.

On October 26, 1992, the Department, OAG, MEC and SRA filed intervenor Direct Testimony. On or about November 20, 1992, the parties filed Rebuttal Testimony.

Public Hearings were conducted on November 10, 1992 in Minneapolis and Bloomington, on November 18, 1992 in Mankato, and on November 19, 1992 in Willmar. Evidentiary hearings are scheduled to begin in St. Paul, Minnesota, on December 8, 1992.

1. TERMS OF SETTLEMENT

This section describes the terms of the Settlement, shows how the testimony or Stipulation of Facts (which will be filed Tuesday December 1, 1992 as Exhibit A) support the Settlement and describes why the Settlement should be approved. *The terms described herein reflect modifications to Joint Exhibit 1 made since the time of the evidentiary hearings. The terms described herein replace the agreements in Joint Exhibit 1 and represent the final agreement among the parties.*

1.1 Overall Description of Stipulation.

Through this Settlement, the parties intend that the agreed- to issues be brought to a close. To that end, the parties have agreed that Minnegasco's proposal to increase its annual Minnesota jurisdictional retail revenues by \$24,823,000 will be reduced. The final revenue requirement and fund rates cannot be determined until the remaining disputed financial and rate design issues have been resolved.

The parties believe this Settlement results in just and reasonable rates for the items settled and is in the public interest. The parties agree that the Commission's decision on disputed issues will not affect the reasonableness of this Settlement. The parties

further agree that the Commission can approve this Settlement without jeopardizing its ability to determine disputed issues, such that the Commission's final decision in this proceeding can result in just and reasonable rates.

1.2 Evidentiary Basis for Settlement.

***44** The parties agree that there is ample evidentiary support for this Settlement, both in prefiled testimony and in the Stipulation of Facts (Exhibit A). The parties offer this Settlement to resolve certain matters and to narrow the scope of contested issues to matters actually in dispute, as encouraged by the Commission and the ALJ. The evidentiary support is described below.

1.2.1 Financial and Capital Issues.

The parties present complete financial schedules detailing the financial impact of this Settlement in Exhibit A, Revised Schedules 1-8. The remainder of this section of the Settlement discusses the parties' agreements on individual financial issues.

a. Rate Base Adjustments

(1) *Pipeline Storage Inventories.* The Department recommended that Minnegasco update its pipeline storage information from its filing by decreasing rate base by \$310,000. This adjustment reflects the updated contract gas costs and volume levels for the test year filed by the Company in Docket No. G-008/M-92-777 which is still pending before the Commission. Layton Direct pp. 117-18. The parties agree to further update the test year for the actual volumes and cost of gas injected into storage and to recognize volumes associated with a new storage contract. Exhibit A, pp. 1-2 and Schedule 9 (*PROPRIETARY*). The parties agree to increase rate base by \$3,546,000 to reflect this adjustment.

(2) *Non-Cash Working Capital.* The Department and the OAG proposed a decrease to the cash working capital component of rate base to remove depreciation and deferred income taxes from the cash working capital calculation. Layton Direct pp. 15-16 and Nelson Direct pp. 13-15. The parties agree to decrease rate base by \$2,990,000 to reflect the adjustment. Exhibit A, p. 2 and Schedule 10.

(3) *Manufactured Gas Plant Deferred Clean-up Costs ("MGP Clean-up Costs").* The Department and the OAG recommended the MGP clean-up costs be shared 50/50 between ratepayers and Minnegasco shareholders. Layton Direct pp. 19-23 and Nelson Direct, pp. 15-21. Minnegasco does not agree to a 50/50 sharing arrangement. The SRA recommended the establishment of an amortization allowance for clean-up costs for all sites incurred since January 1, 1992. The amortization would take place over a rolling ten year period with no rate base treatment. Towers Direct, pp. 4-11. The parties agree to remove all deferred MGP clean-up costs and related accumulated deferred income taxes from rate base. It is agreed to remove \$1,661,000 of average deferred MGP clean-up costs, Daugherty Direct, Schedule 10, p. 1, and the offsetting related \$672,000 of accumulated deferred taxes, Daugherty Direct, Schedule 4, p. 3, from rate base. Exhibit A, p.3 and Schedule 11. See the Income Statement section for the impact on operating expenses.

(4) *Compressed Natural Gas (CNG) Assets.* The Department and the OAG proposed that all gross assets associated with Minnegasco's investment in its CNG facilities be removed. Chavez Direct, pp. 54-60, Kosowski Direct, pp. 15-16, and Nelson Direct, pp. 26-29. The parties agree to remove net CNG assets of \$700,925 and related offsetting accumulated deferred taxes of \$138,622 from rate base. Exhibit A, p.3 and Schedule 12. See Income Statement for the impact of this adjustment on depreciation expense.

***45** (5) *Prepaid Taxes on Unbilled Revenues.* The Department recommended removing the prepaid taxes on unbilled revenues from rate base. Layton Direct, pp. 13-15. The OAG offered three adjustments for unbilled revenues and recommended one. The OAG recommended amortizing the unbilled revenues to income over a period of time for ratemaking purposes and retaining Minnegasco's proposed adjustment for prepaid taxes on unbilled revenues. Nelson Direct, pp. 4-13.

<<- The parties agree to reduce Minnegasco's revenue requirement by recognizing unbilled revenues for regulatory purposes over twenty (20) years (see Income Statement section) and to recognize the related — accumulated deferred income taxes on unbilled revenues in rate base. ->>The parties agree to resolve all unbilled revenues issues in this proceeding by decreasing rate base by \$13,260,000 for the prepaid taxes on unbilled revenues. <<- and to increase rate base by \$1,070,389, Exhibit A, p.3 and Replacement Schedule 13., for the accumulated deferred income taxes on the unbilled revenues. ->>

(6) *Conservation Improvement Program (CIP) Tracker Balance.* The parties agree that if approved final rates result in an interim rate refund to customers, the refund will be offset by the CIP tracker balance of \$1,413,278. Hagen Direct, Schedule 19, p. 1. If any interim rate refund is not large enough to completely offset the CIP tracker balance, the parties agree to reduce the tracker balance by the amount of the refund and to amortize the remaining tracker balance over five years, with rate base recognition of the unamortized balance. If approved final rates do not result in any interim rate refund, the parties agree to amortize the CIP tracker balance over five (5) years, with rate base treatment of the unamortized balance, increasing rate base by \$212,000. Exhibit A, p.4 and Schedule 14. See the income statement section of this Settlement for the impact of this agreement on operating expenses.

(7) *Rate Case Expense Unamortized Balance.* The Department recommended that rate case expenses be shared 50/50 between ratepayers and Minnegasco shareholders together with an amortization of those remaining costs over five (5) years. Zamansky Direct, pp. 7-9. Minnegasco does not agree to a 50/50 sharing arrangement. The parties agree to amortize the rate case expenses over five years and to remove the average rate case expense balance of \$604,000, Daugherty Direct, Schedule 10, p. 3, from rate base. Exhibit A, p. 4 and Schedule 15. See Income Statement section for impact of the five (5) year amortization.

(8) *Cash Working Capital.* The Department recommended removing the zero day items from cash working capital, recalculating the change in the late payment revenues based on a 2.2 day adjustment instead of Minnegasco's proposed 4.4 days, and recalculating the lead-lag study based upon the revised level of operating expenses. Layton Direct, pp. 16-17. The parties agree to recalculate Minnegasco's cash working capital with the removal of zero-day items, use a zero 2.2 day impact of the change in the late payment policy for commercial/industrial customers rather than a 4.4 day impact proposed by Minnegasco, and to calculate the revised level of operating expenses as finally determined by the Commission. The parties have recalculated cash working capital based on the operating expenses agreed to in the Settlement in order to determine the revenue required under the Settlement. Exhibit A, p.4 and Replacement Schedule 16.

***46** (9) *Headquarters Allocations.* The parties agree to decrease rate base by \$271,563 associated with the joint use of furniture and fixtures, personal computers and office equipment in the Minnegasco headquarters building located in downtown Minneapolis. This rate base adjustment is based upon an allocation factor to unregulated activities of *** Begin Proprietary *** See Income Statement, Section 19, Proprietary Schedule 28 for an explanation of and calculation of this allocation factor.

The parties acknowledge that the allocation of Minnegasco's costs between its regulated and non-regulated businesses are at issue in the complaint made by the Minnesota Alliance for Fair Competition (MAC), Docket No. G-008/CI-91-942. The parties agree that this settlement or elements thereof shall not have any precedential effect on the MAC complaint proceedings for any purpose. The parties further agree that no party to this settlement is estopped from contesting any factual or legal issue in the MAC complaint and that no party has waived the right to challenge the appropriateness of any allocation process, method, or practice in the MAC complaint docket.

b. Income Statement

(1) *Correction of errors.* Minnegasco identified errors in its original filing in Ms. Reimer's rebuttal testimony. Reimer Rebuttal, Schedule 2, p. 10. *An additional correction was found since the close of hearings to remove the cost of merchandise from total appliance sales expense for the purpose of computing an allocation factor applied to accounting costs. This reduces the allocation correction presented in Ms. Reimer's rebuttal testimony. The calculation of this reduction and the revised correction*

of <<- these errors ->> are shown in Exhibit A, replacement Proprietary Schedule 17 and reduces revenue requirements by \$110,917. <<- \$138,375. Exhibit A, p. 5 and ->> <<- Schedule 17. ->>This amount includes the correction of an inflation adjustment error identified by the Department during their audit. The parties agree to reduce revenue requirements by \$110,917 <<- \$138,375 ->>to correct these errors.

(2) *Employee and Corporate Dues.* The Department and OAG recommended that certain employee and corporate dues be disallowed. Zamansky Direct, pp. 5-6 and Nelson Direct, pp. 29-31. The parties agree to remove \$25,601 for certain employee dues and \$6,000 for U.S. Chamber of Commerce dues. Zamansky Direct, pp. 5-6.

(3) *Marketing Expenses.* The Department recommended the marketing expenses related to Minnegasco's desiccant cooling, irrigation water pumping and natural gas vehicle (NGV) programs be disallowed. Kosowski Direct, pg. 13-15. The parties agree to remove \$541,442 of marketing expenses for these programs.

(4) *Advertising Expenses.* The Department recommended removal of certain Minnegasco advertising costs. Specifically, the Department recommended removal of twenty-five (25) percent of Minnegasco's customer information pamphlet, *In-Touch*, 100 percent of advertising account #913, and a portion of advertising account #930. Kosowski Direct, pg. 16-19. The parties agree to reduce revenue requirements by \$297,565 for these costs.

***47** (5) *Flowers/Tickets/Lobbying Meals/ Veterans Club.* The OAG recommended removal of the costs associated with these items. Nelson, Direct, pg 40. The parties agree to reduce revenue requirements by \$10,718 for the cost of flowers, tickets and lobbying meals. Exhibit A, p.5 and Schedule 18.

(6) *Carbon Monoxide (CO) Leak Checks.* As determined by the Commission in Docket No. G-008/C-91-942, the cost of CO checks should not be borne by the ratepayers and should not be allocated to the utility. *Certain errors were identified with this adjustment. However, the impact of these errors was de minimus. Therefore,* The parties continue to agree to reduce revenue requirements by \$224,217 for the direct cost of CO checks. *See Proprietary Schedule 30.*

(7) *Economic Development.* The Department recommended disallowance of all economic development costs. The Department and the OAG recommended only one-half of the economic development costs be allowed if the cost-benefit of these costs are demonstrated. Kosowski Direct, pp. 19-20 and Nelson Direct, pp. 21-24. The parties agree to disallow one-half of these costs, reducing revenue requirements by \$27,500. Exhibit A, Schedule 19.

(8) *Lobbying Expenses.* The OAG proposed to remove Minnegasco's lobbying expenses. Nelson Direct, pp. 24-25. The parties agree to remove these expenses, reducing revenue requirements by \$136,609.

(9) *Incentive Compensation.* The OAG recommended the disallowance of incentive compensation costs. Morrisette Direct, pp. 17-21. Minnegasco's incentive compensation payments are tied to the achievement of both employees' personal goals and Minnegasco's and Arkla's financial goals. Hagen Direct, p. 71. The parties agree to disallow 60% of management incentive compensation costs, reflecting the companies' financial goals, reducing revenue requirements by \$251,314. Exhibit A, pp. 5-6 and Schedule 20.

(10) *In-Kind Contributions.* The OAG recommended that one-half of Minnegasco's in-kind charitable contributions be excluded. Nelson Direct, pp. 25-26. The parties agree to reduce revenue requirements by \$2,375 to reflect this adjustment.

(11) *MGP Clean-Up Costs.* In its rate case filing, Minnegasco requested total test year expenses associated with MGP clean-up of \$5,060,277. This amount consists of \$2,975,000 in test year expenses for remediation of the former Minneapolis Gas Works plant, legal fees associated with the Park Board lawsuit of \$403,000 and investigation costs of other Minnesota MGP sites of \$575,000. The Company also included deferred expenses of \$2,214,554 for the period beginning in 1991 through June 30, 1992, amortized over two years, resulting in \$1,107,277 of test year expenses. Hagen Direct, Schedule 17. The Commission disallowed

the pre-1992 deferred balance of MGP clean-up costs in Docket No. G-008/M-91-1015. The parties agreed to decrease expenses by the \$482,277 in pre-1992 costs which Minnegasco amortized to operating expense in the filing.

***48** The DPS and the OAG recommended that the remaining amortized balance and test year expense be shared 50/50 with Minnegasco shareholders. Layton Direct, pp. 19-23 and Nelson Direct, pp. 15-21 (see Rate Base section for the SRA position. Minnegasco does not agree to a 50/50 sharing arrangement. The parties agree to recognize ongoing, annual MGP clean-up costs and legal fees of \$3.1 million. No deferred accounting of MGP clean-up costs will occur after December 31, 1992. Further, as a result of Docket No. G-008/M-91-1015, the Company began deferring MGP costs beginning January 1, 1992. However, the Company received no interim rate recovery for MGP costs. Therefore, the parties agree to amortize the estimated 1992 deferred balance of \$2,500,000 to expenses over five years, with no rate base treatment of the unamortized balance. This results in a total test year expenditure (including amortization) of \$3,600,000, requiring a reduction in revenue requirements of \$1,460,000 from the Company's original filing. Exhibit A, p. 6 and Schedule 21.

Minnegasco will place any insurance recoveries in a deferred debit account without carrying charges, until its next rate filing. Net insurance proceeds will be flowed back to ratepayers.

(12) *CNG Expenses*. The Department and OAG recommended the removal of CNG assets from rate base. See Rate Base section. The removal of the related depreciation expense associated with those assets is a reduction in revenue requirements of \$33,603.

The parties recognize that the Energy Policy Act of 1992 encourages the development of alternative fuel vehicles. For purposes of settlement in this case, other than \$18,458 associated with the Company's own fleet of vehicles which operate on CNG, the parties agree that the revenue requirements associated with the marketing, depreciation, O&M expenses and return on certain investments of Minnegasco's CNG vehicle program will not be reflected in the rates ultimately determined in this case. Lack of recognition of these costs in this case shall be without prejudice to Minnegasco's right to request full rate case treatment of these and similar costs in its next rate case and shall not be deemed of any precedential value in this or any other proceeding. The parties agree to a reduction in revenue requirements of \$52,061 for this issue. Exhibit A, pp. 6-7 and Schedule 22. See CNG Assets and Marketing Expenses for other revenue requirement impacts.

<<- (13) ->> *Unbilled revenues*. The parties ->> <<- agree to reduce Minnegasco's revenue requirement by recognizing unbilled revenues for regulatory purposes each year over 20 years. This adjustment reduces revenue requirements by \$481,771. Exhibit A, p. 7 and Schedule 23. ->>

(13) *Allocation of Senior Officer's Pay*. The parties agree to remove \$24,193 in senior officer's pay due to updated 1992 percentages and a change in the allocation factor for certain senior officers to a factor based on the ratio of non-utility operating expenses to company operating expenses, removing cost of goods sold. See Proprietary Replacement Schedule 23 for calculation of this adjustment.

***49** (14) *Industrial Heating Sales Volumes*. The Department proposed an increase to the forecasted volumes for the industrial heating sales class based upon a higher level of customers in that class than Minnegasco proposed. O'Connell Direct, pp. 7. The parties agree to increase revenues by \$1,087,600, increase cost of gas by \$626,500, increase late payment revenues by \$5,656 and increase bad debt expense by \$8,755 for this adjustment. This adjustment decreases Revenue requirements by \$458,001. Exhibit A, p.7 and Schedule 24. Schedule 24 also provides a monthly breakout of the stipulated sales volumes by class.

(15) *Inflation on Adjusted Expenses*. Certain expenses that were removed for settlement were separately inflation impacted within Minnegasco's filing. The parties agree to reduce revenue requirements by \$42,965 to remove the related inflation for those items. Exhibit A, p. 8 and Schedule 25.

(16) *CIP Tracker Balance*. The Department recommended a five (5) year amortization of the underrecovered CIP tracker balance to the extent, if any, the balance is not offset by a rate refund. See Rate Base section. The parties agree to reduce amortized CIP expenses, and therefore revenue requirements, by \$423,983. Exhibit A, pp. 8-9 and Schedule 26.

(17) *Rate Case Expense*. As identified in the Rate Base section, the parties agree to amortize Minnegasco's rate case expense over five (5) years as recommended by the DPS. This reduces revenue requirements by \$241,431.

(18) *Coopers & Lybrand Audit*. The parties agree to remove \$38,540 with respect to the Coopers & Lybrand audit. Bender Direct, pp. 10-11.

(19) *Headquarters Allocations*. The parties agree to remove *** Begin Proprietary *** expenses associated with joint and common headquarters costs which are currently charged to the utility operations. The adjustment reflects an allocation between Minnegasco's regulated and unregulated activities for headquarters rent, property taxes and maintenance, including utilities, as well as depreciation on shared furniture and fixtures, personal computers and office equipment. The expense adjustment is based on an average for each floor of the allocated payroll and other expenses for shared divisions. The weighted average factor of *** Begin Proprietary*** Proprietary *** and the Minnesota jurisdictional factor are applied to total company expenses for these items to derive the adjustment. See Exhibit A, Proprietary Schedule 29, for the calculation of the allocated expense adjustments and the allocation factor.

c. Rate of Return

(1) Capital Structure. Minnegasco proposed the following capital structure:

- a. debt of 48.34%;
- b. common equity of 51.66%;
- c. total of 100.00%.

The Department agreed with Minnegasco's proposed capital structure. Thompson Direct, p. 31. None of the other parties took issue with the filed capital structure. The parties agreed to use the capital structure proposed by Minnegasco.

(2) Cost of Capital. Minnegasco proposed that the cost of its long-term debt is 4.47%. No party disagreed. Minnegasco proposed a return on equity of 13% using both the constant growth and general forms of the DCF model on a group of sixteen comparable companies. The Department recommended a return on equity of 11.5% based on its application of the DCF model. MEC recommended a return on equity of 9.75% based on its DCF analysis. The parties agree to use the Department's recommended return on equity of 11.5% and the cost of debt-proposed by Minnegasco. Along with the agreed upon capital structure, this results in an overall rate of return of 10.41%. Thompson Direct, p. 31.

d. Weather Normalization Adjustment (WNA)

***50** The parties agree to remove the issue of a weather normalization adjustment from this proceeding. The parties further agree that Minnegasco may not file to implement a WNA until its next rate case.

e. Rate Design and Other

(1) Residential Sales Service. Minnegasco proposed several changes in the prices and services offered to residential customers presently receiving Small Volume Firm Gas Service. Bridge Direct pp. 7-8; Chavez Direct, pp. 9, Morrisette Direct pp 3-4. The parties agree only on the following changes:

- (a) To adopt Minnegasco's proposal to create a new Residential Sales Service customer class.
- (b) To increase revenues 7.3% for the new customer class. However, the parties also agree to reduce this increase proportionately based upon reductions in the final revenue deficiency, in order for Minnegasco to realize only the total revenue increase authorized by the Commission.
- (c) To eliminate the three Ccfs of usage allowance included in the monthly customer charge.

Minnegasco's other proposed changes regarding rate design for residential customers remain contested and the parties will litigate those issues.

(2) Commercial and Industrial Sales Service. Minnegasco proposed several changes in the prices of services offered to commercial and industrial customers presently receiving Small Volume Firm Gas Service. The parties have reached agreement on several of these issues, as follows:

(a) Minnegasco proposed to divide the current Small Volume Firm Gas Service customer class into two groups: a Residential class and a Commercial and Industrial class. The Department recommended that Minnegasco further divide its proposed Commercial and Industrial class into two separate classes: (1) Commercial and Industrial Sales Service for commercial and industrial customers with daily usage less than 200 Mcf; (2) Large Volume Commercial and Industrial Sales Service for commercial and industrial customers with daily usage greater than or equal to 200 Mcf. Chavez Direct, p. 17-19. The parties agree to adopt Minnegasco's proposal, together with the Department's recommendation to further divide the Commercial and Industrial Sales Service customer class.

(b) Minnegasco proposed a 4.0% increase in class revenue for the Commercial and Industrial Sales Service class. The Department proposed a 2.63% increase in class revenue for its Commercial and Industrial class and no increase in class revenue for its Large Volume Commercial and Industrial class. Chavez Direct, pp. 19-20. The parties agree to adopt the Department's proposed revenue responsibility for the two commercial and industrial classes. The parties further agree to reduce the 2.63% increase in class revenue for the Commercial and Industrial class proportionately based upon reductions in the final revenue deficiency, in order for Minnegasco to realize only the total revenue increase authorized by the Commission.

(c) The Department proposed increasing the monthly customer charge for the Commercial and Industrial customer segments as follows: (1) Commercial and Industrial customers with annual usage of less than 150 Mcf would have a \$10 monthly customer charge; (2) Commercial and Industrial customers annual usage equal to or greater than 150 Mcf (with daily usage less than 200 Mcf) would have a \$30 monthly customer charge; (3) Commercial and Industrial customers with *daily* usage equal or greater than 200 Mcf would have a \$100 monthly customer charge. Chavez Direct pp. 20-22. The OAG raised concern over the total revenue responsibility allocated to the smallest Commercial & Industrial customers. Morrisette Rebuttal, pp. 3-4. The parties agree to a \$9 customer charge for Commercial & Industrial customers with annual usage of less than 150 Mcf and the Department's recommended customer charges for all other Commercial & Industrial customers.

***51** (d) The parties agree to eliminate the three Ccfs of usage allowance from the monthly customer charge, as proposed by Minnegasco.

The parties will litigate the remaining Commercial & Industrial Sales Service issues.

(3) Small Volume Dual Fuel Service. Minnegasco proposed several changes in the prices and service offered to dual fuel customers presently receiving Small Volume Interruptible Service. The parties agreed as follows:

(a) The Department recommended a modification to Minnegasco's proposed name changes. The Department agreed with Minnegasco's change from interruptible services to Dual Fuel Services, however recommended that Minnegasco retain the Small Volume designation to avoid customer confusion with Large Volume Dual Fuel Services. The parties agreed to change the name of these services to Small Volume Dual Fuel Service.

(b) The Department agreed that an increase in class revenues is reasonable, but recommended a 7.9% increase. The parties agree with the Department's recommended 7.9% increase in class revenues. The parties also agree that the 7.9% increase in class revenues will be adjusted further to recognize the proportionate decrease in revenue responsibility necessary to allow Minnegasco to recover only the total revenue increase authorized by the Commission.

(c) The parties agree to adopt the Department's recommendations for monthly customer charges of \$75 for Small Volume Dual Fuel Sales Services and \$175 for Small Volume Dual Fuel Transportation services. Chavez Direct pp. 26-27.

(d) The Department recommended a single unit margin for Small Volume Dual Fuel services. The parties agree to adopt the Department's recommendation for a single unit margin for all Small Volume Dual Fuel services, calculated as described on page 15 of Mr. Chavez's Direct Testimony.

(e) The Department recommended that Minnegasco maintain the ability to negotiate the flexible unit margin up, by the same increment as it has authority to flex the unit margin down. The parties agree to establish Minnegasco's maximum flexible unit margin accordingly. For example, if the standard unit margin is \$0.60, the increment Minnegasco is authorized to flex the unit margin down is \$0.55 (\$0.60 - \$0.05 minimum = \$0.55). Therefore, the maximum flexible unit margin would be \$1.15 (\$0.60 + \$0.55 flexible margin increment).

(f) The parties agree to adopt Minnegasco's proposals for modification of transportation tariffs to incorporate a number of balancing provisions. Chavez Direct, p. 32.

(4) Large Volume Dual Fuel Services. Minnegasco proposed several changes in the prices and services offered to large dual fuel customers presently receiving Large Volume Interruptible Gas Service. The parties agree to the following:

(a) The parties agree to adopt Minnegasco's recommendations for name changes from Large Volume Interruptible to Large Volume Dual Fuel services.

(b) The parties agree that the imputed margin that the Company will receive from its Market Rate Transportation customers is *** Begin Proprietary *** A, p. 9 and Proprietary Schedule 27. The difference between the Company's proposed imputed margin of *** Begin Proprietary *** Proprietary *** will decrease the standard unit margin for Large Volume Dual Fuel Sales and Transportation customers.

***52** (c) The parties agree to adopt Minnegasco's proposed monthly customer charges of \$200 for sales services and \$300 for transportation services.

(d) The Department recommended that Minnegasco maintain a single unit margin rate, decreased from the present unit rate to offset the revenue increase derived from the increases in the monthly customer charges. The parties agree to adopt the Department's recommendation.

(e) The Department agreed that Minnegasco should maintain its ability to flex its unit margin up by the same increment Minnegasco has authority to flex its unit rate down. The parties agree to adjust Minnegasco's maximum unit rate to the same

increment above the standard unit rate as Minnegasco has authority to reduce its standard unit rate. For example, if Minnegasco has authority to reduce its standard rate by \$.45 (\$.50 standard rate - \$.05 minimum), the maximum rate would equal \$.95 (\$.50 standard rate + \$.45 flexible increment).

(f) The parties agree to adopt Minnegasco's proposed modifications to the transportation service tariffs to incorporate a number of balancing provisions. Bridge Direct, p. 33.

(5) Developmental Services. Minnegasco proposed six new Developmental Services. The parties agreed to the following items with respect to these proposed services:

(a) Standby Peaking Sales Service. The parties agree to adopt Minnegasco's proposals for this new service. Chavez Direct, pp. 41-42.

(b) Firm Transportation Service. The Department recommended that Minnegasco offer two different rates for firm transportation customers, consistent with the agreed-upon rates established for the Commercial and Industrial Sales Service customer classes. In addition, the Department proposed that \$100 be added to the monthly Sales Service customer charges for the Transportation Service customers. Chavez Direct, p. 39. The parties agree to adopt the Department's recommendations for two separate Firm Transportation services and to adopt the Department's proposed customer charges.

(6) Class Cost of Service Study (CCOSS). The Department and Minnegasco provided different CCOSSs. The Department's CCOSS did not provide significantly different results as compared to Minnegasco's CCOSS. The parties agree to the Department's CCOSS. Ahrens Rebuttal.

2. IMPLEMENTATION.

The parties intend that this Settlement resolve only those issues expressly addressed in this Settlement.

3. PROPOSED PROCEDURAL SCHEDULE.

This Settlement contemplates that hearings will begin on December 8, 1992, on all issues not settled by this Settlement. The parties will also make their witnesses available to Commission staff to answer any questions concerning the components to this Settlement. The parties will request the ALJ to separately advise the Commission on the reasonableness of this Settlement, so that the Commission has the opportunity to rule on this Settlement at the earliest possible time.

4. SETTLEMENT AS A COMPROMISE.

***53** The parties agree that this Settlement has been entered into as an overall compromise and resolution of the issues presented in this Settlement in order to minimize litigation and controversy. The parties further agree and stipulate that this Settlement does not represent the position, in *total* or on any individual issue, that the parties would have taken had the issues in this proceeding been fully litigated, and this Settlement, whether or not adopted by the Commission, shall not be cited or otherwise used to imply the contrary.

5. ACCEPTANCE OF SETTLEMENT.

The agreement in this Settlement is expressly conditioned on its acceptance by the Commission in its entirety without modification. Pursuant to [Minn. Stat. § 216B.16, subd. 1\(a\)](#), if the Commission modifies this Settlement, the parties shall have ten (10) days in which to reject this modification. If any party rejects the modification, the parties agree that this Settlement

shall be null and void and shall not constitute any part of the record in this proceeding. In such event, the parties agree that any rebuttal testimony and cross-examination which was exchanged but not filed due to the pendency of this Settlement shall be filed and hearings should go forward promptly upon all matters raised in the testimony of the parties to the proceeding and that all parties be permitted to argue their positions with respect to such issues to the Commission in post-hearing briefs and, if requested or permitted by the Commission, oral argument.

SETTLEMENT BENEFITS.

This Settlement is in the public interest. It reduces Minnegasco's requested revenue requirements by approximately \$11,000,000 based on an overall rate of return of 10.41%. The parties believe that this Settlement, along with the Commission's resolution of the remaining disputed issues, can result in just and reasonable final rates.

The parties agree that there is ample evidentiary basis for this Settlement in the prefiled testimony and in the attached Stipulation of Facts to resolve all possible contested issues, as encouraged by [Minnesota Statutes § 216B.16, \(1\)\(a\)\(1992\)](#) and the Prehearing Order in this case.

CONCLUSION.

This Settlement is a negotiated agreement, arrived at between the parties for the purpose of resolving the contested revenue requirement and rate design matters in this proceeding in an equitable fashion, consistent with the public interest. As a result, the parties agree that the resolution of the contested issues made in this Settlement established no precedent for resolution of these issues in the future.

While the parties have different positions on the numerous issues raised in this case, they have worked together to arrive at a just and reasonable resolution of this proceeding on terms that treat all parties fairly, and that protect the public interest. The parties respectfully request that the ALJ recommend that the Commission adopt findings and conclusions in its entirety in accord with this Stipulation.

Footnotes

- 1 This transaction is being reviewed separately in Docket No. G-008, 010/PA-93-92, *In the Matter of a Joint Petition From Minnegasco and Midwest Gas for Authority to Exchange Assets, Utility Operations and Business*.
- 2 Minnesota Energy Consumers (MEC), a party to this proceeding but a non-signatory of the Settlement, challenged the reasonableness of the Settlement's revenue apportionment. As discussed in greater detail in the Rate Design section of this Order (page 25, *infra*), the Commission rejected MEC's challenge and found that the revenue apportionment proposed in the Settlement was fair and reasonable.
- 3 *In the Matter of the Accounting and Ratemaking Effects of the Statement of Financial Accounting Standards No. 106*, Docket No. U-999/CI-92-96, ORDER ADOPTING ACCOUNTING STANDARD AND ALLOWING DEFERRED ACCOUNTING (September 22, 1992).
- 4 *In the Matter of the Petition of Minnesota Power & Light Company, d/b/a Minnesota Power, for Authority to Change Its Schedule of Rates for Retail Electric Service in the State of Minnesota*, Docket No. E-015/GR-87-223 FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (March 1, 1988).
- 5 *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Gas Utility Service Within the State of Minnesota*, Docket No. G-002/GR-86-160, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (January 27, 1987).
- 6 *Re Coal Tar Cleanup Expenditures*, Docket No. 91-0080 *et al*, Order dated September 30, 1992.

- 7 See, for example, *In the Matter of a Petition from Northern States Power Company for a Variance to the Purchase Gas Charges, Automatic Adjustment Rule for Recovery of Carrying Costs Associated with Gas Storage Service*, Docket No. G-002/M-90-630, ORDER GRANTING VARIANCE FOR ONE YEAR, April 4, 1991 and ORDER EXTENDING VARIANCE AND SETTING FILING REQUIREMENTS, December 10, 1991.
- 8 *In the Matter of the Accounting for and Recovery of Conservation Expenses by Minnegasco, Inc.*, Docket No. G-008/CI-88-460, ORDER MODIFYING AND APPROVING COST RECOVERY PROPOSAL AND REQUIRING FILING, September 1, 1989.
- 9 See, for example, *In the Matter of the Proposal of Northern States Power Company's Gas Utility for a Demand-Side Management Incentive Mechanism*, Docket No. G-002/M-92-516, ORDER APPROVING DEMAND-SIDE MANAGEMENT FINANCIAL INCENTIVE PLAN WITH MODIFICATIONS AND REQUIRING FURTHER FILINGS, January 7, 1993.
- 10 See, *In the Matter of the Proposal of Otter Tail Power Company for a Demand-Side Management Financial Incentive*, Docket No. E-017/M-91-457, ORDER ESTABLISHING DEMAND SIDE MANAGEMENT INCENTIVE PILOT PROJECT AND REQUIRING FURTHER FILINGS, March 12, 1992.
- 11 *In the Matter of the Application of Interstate Power Company for Authority to Increase Its Rates for Electric Service in the State of Minnesota*, Docket No. E-011/GR-91-605, FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER (June 12, 1992).
- 12 Staff notes that NSP-Electric's tariff on Continuity of Service was a part of NSP's tariffs prior to electric and gas utilities becoming rate regulated in Minnesota in 1974. The propriety of this kind of language has not come before the Commission for deliberation prior to it becoming an issue in this docket.
- 13 *In the Matter of a Request by Northern Minnesota Utilities for Approval of a New Town Rate*, Docket No. G-007/M-92-212, ORDER APPROVING TARIFF WITH MODIFICATIONS AND REQUIRING FURTHER FILING (May 6, 1992).
- 14 *In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in the State of Minnesota*, Docket No. E-002/GR-91-1, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER (November 27, 1991).